REVIEW MEMORANDUM
7 DE Admin. Code 1130 (TITLE V) DRAFT OPERATING PERMIT
For Significant Permit Modification
Delaware City Refining Company

4550 Wrangle Hill Road
Delaware City, Delaware 19706
PERMIT: AQM-003/00016 – Parts 1, 2 and 3 Draft – Significant Permit Modification

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MEMORANDUM SETUP:

This memorandum constitutes the technical and regulatory review of an application submitted by Delaware City Refining Company (DCRC) for a significant permit modification to its Regulation No. 1130 (Title V) permit. Its purpose is to describe the emission units and applicable requirements in support of the attached draft modified Title V Operating Permit for the above facility. The memorandum is setup in the following format:

I. Glossary of Abbreviations and Acronyms Used

II. Background
Identification of Emission Units
Chronology of Correspondence

III. Discussion on the proposed significant permit modification

The applicable requirements as they pertain, based upon a technical and regulatory review, to the emission units and insignificant activities identified by the Company are discussed in the remainder of this memorandum. The regulatory review will indicate those applicable requirements that are "state only enforceable." All other applicable requirements unless otherwise indicated are both state and federally enforceable.

Historically, this permit was structured in 3 parts because of the inherent complexity of this facility, the fact that the majority of process units are major sources in and of themselves, and finally because each part was developed independently. However, since all 3 parts have been issued and because all 3 parts have the same general requirements, it now makes sense to consolidate them into one permit having a common general section while maintaining the former partial structure for the unit specific emissions requirements. Accordingly, the attached operating permit satisfying the requirements of 7 **DE Admin. Code 1130** covers all the emission units formerly identified in parts 1, 2 and 3 within the body of a single permit.

IV. Operational Flexibility

V. Compliance Schedule

VI. Permit Shield

I. Glossary of Abbreviations and Acronyms Used

Alkylation Unit	ALKY
Ambient Air Quality Standards	AAQS
Air Pollution Control Device	APCD
Alternate Monitoring Plan	AMP
Atmospheric Tower Heater	ATH

Baghouse	BG
Barrels per Hour	BPH
Barrels per Day	BPD
Barrels per Year	BPY
Batch Process	BP
Best Available Control Technology	BACT
Carbon Canister	CC
Carbon monoxide Boiler	COB
Catalytic Hydrodesulfurizer Unit	CHU
Clean Air Act Amendments	CAAA
Code of Federal Regulations	CFR
Continuous Catalyst Regeneration	CCR
Continuous Emissions Monitoring System	CEMS
Continuous Emissions Rate Monitoring System	CERMS
Crude Unit	CU
Cylinder Gas Audit	CGA
Delaware City Refinery	DCR
Delaware City Refining Company	DCRC
Department of Natural Resources and Environmental Control	DNREC
Diethanolamine	DEA
Diglycolamine	DGA
Dissolved Nitrogen Floatation	DNF
Division of Air Quality	DAQ
Emissions Offset Program	EOP
Ether Plant	EP
Ethyl Tertiary Butyl Ether	ETBE
Excess Emissions Report	EER
Facility Wide Requirement	FWR
FCCU NOx Agreement	FNA
Flare Gas Recovery	FGR
Fluid Catalytic Cracking Unit	FCCU
Fluid Coking Unit	FCU
Frozen Earth Storage	FES
Gasoline Dispensing Facility	GDF
Good Engineering Practice	GEP
Hazardous Air Pollutant	HAP
Hydrocracker Unit	HCU
Hazardous Organic NESHAP	HON
Hydrogen Plant	HP
Lowest Achievable Emission Rate	LAER
Leak Detection and Repair	LDAR
Marine Vapor Recovery	MVR
Material Safety Data Sheets	MSDS
Maximum Achievable Control Technology	MACT
Methyl tertiary butyl ether	MTBE
National Ambient Air Quality Standard	NAAQS
National Emission Standards for Hazardous Air Pollutants	NESHAP

New Source Performance Standards	NSPS
New Source Review	NSR
Oil Recovery System	ORS
Olefins Plant	OP
Polymerization Unit	POLY
Potential to Emit	PTE
Prevention of Significant Deterioration	PSD
Reasonably Available Control Technology	RACT
Refinery Flare System	RFS
Refinery Gas Plant	RGP
Refinery Tank Farm	RTF
Reformer/Reformulated Gasoline 2000 Project	RFG2K
Relative Accuracy Test Audit	RATA
Selective Hydrogenation Unit	SHU
Shell Claus Offgas Treatment Unit	SCOT Unit
Selective Non Catalytic Reduction	SNCR
Spent Caustic Stripper	SCS
South Coke Storage Area	SCSA
Steam Methane Reformer Hydrogen Plant	SMRHP
Sulfur Recovery Area	SRA
Synthetic Organic Chemical Manufacturing Industry	SOCMI
Tertiary amyl methyl ether	TAME
Tank with fixed cone roof	TC
Tank with floating roof	TF
Thermal oxidizer	TO
Total annual benzene	TAB
Upgrade and Optimization Project (aka "Bin 1 Project")	UOP
Vacuum Tower Heater	VTH
Vapor combustion unit	VCU
Vapor Recovery Unit	VRU
Volatile Hazardous Air Pollutant	VHAP
Volatile Organic Compound	VOC
Wet Gas Scrubber	WGS
Waste Water Treatment Plant	WWTP

II. **Background**:

The Delaware City Refinery (DCR), NAICS Code 32411, is located on a 5,000 acre tract in Delaware City and between US Route 13 and Delaware Route 9. The DCR has the potential to emit greater than 25 tons per year NO_x and VOCs, greater than 100 tons per year SO_2, greater than 100 tons per year CO, and greater than 25 tons per year hazardous air pollutants (HAPS) listed in Section 112(b) of the CAAA of 1990. Therefore, the DCR is subject to 7 **DE Admin. Code 1130**.
The DCR was owned by Star Enterprises at the time the title V application was submitted to the Department. On July 1, 1998, Shell Oil Products (Shell), Saudi Refining, Inc., and Texaco Inc. formed Motiva, combining the major elements of Shell's and Star's eastern and southern refining and marketing businesses. The ownership of Star Enterprise was transferred to Motiva L.L.C. on October 1998. In October 2001, Texaco Inc. divested itself of its share in the Company. Motiva sold the DCR to The Premcor Refining Group, Inc. on May 1, 2004. On September 1, 2005, Premcor, in turn, was acquired as a wholly owned subsidiary by The Valero Energy Corporation (Valero). The

Delaware City Refining Company (DCRC) acquired the DCR from Valero on May 31, 2010. Prior to reaching agreement with DCRC for the sale of the refinery, Valero (the previous owner) initiated a temporary cessation of operations at the refinery and proceeded to de-inventory several of the process units pending implementation of a program to permanently cease operations. DCRC is currently undergoing a maintenance turnaround in order to ensure the safe and environmentally protective re-start of refinery operations.

On May 31, 2010, the Delaware Department of Natural Resources and Environmental Control (DNREC) and DCRC entered into an agreement to address and clarify certain environmental regulatory considerations relevant to DCRC's acquisition and operation of the DCR.[1] Section I of this agreement provides for the establishment of a facility wide NOx emission limitation for all permitted sources at the DCR. In order to implement the facility wide NOx emission limitation for all permitted sources at the DCR ("the NOx cap"), DCRC was required to submit a permit application for a significant permit modification to its TV permit by August 15, 2010. DCRC's permit application dated August 15, 2010 was received by the Department on August 17, 2010 and considered to be timely. The application is signed by James Fedena, Sr. Vice President, HSE who is also the designated Responsible Official as defined in 7 **DE Admin. Code 1130**.

Identification of Emission Units:

Tables 1, 2 and 3 identify the emission points and emission units subject to Parts 1, 2 and 3 of this Title V operating permit:

Table 1: Emissions Units Covered By Part 1

Emission Unit	Emission Point	Emission Point Description
HDS	29-1	Catalytic Hydrodesulfurizer Train 1 feed heater (29-H-101) and fractionator heater (29-H-8)
	29-2	Catalytic Hydrodesulfurizer Train 2 feed/fractionator heater (29-H-2), Train 3 feed heater (29-H-3) and fractionator reboiler heater (29-H-9)
	29-3	Catalytic Hydrodesulfurizer Train 4 feed heater (29-H-4) and Train 4 fractionator heater (29-H-7)
	29-4	Catalytic Hydrodesulfurizer Train 5 fractionator heater (29-H-6) and Train 5 feed heater (29-H-5)
Tetra	Fugitives	Tanks
	32-1	Tetra unit feed heater (32-H-101)
SHU	33-1	Selective Hydrogenation unit startup heater (33-H-1)
	33-2	Selective Hydrogenation unit startup heater (33-H-2)
Olefins	34-1	Olefins reboiler heater (34-H-101)
HC	36-1	Hydrocracker unit feed heater (36-H-1)
	36-2	Hydrocracker unit column reboiler (36-H-2)

[1] Agreement governing the Acquisition and Operation of Delaware City Refinery dated May 31, 2010 herein after referred to as the DCRC Agreement.

Emission Unit	Emission Point	Emission Point Description
	36-3	Hydrocracker unit fractionator reboiler (36-H-3)
FES	40-1	Refinery frozen earth propane storage flare system
TF	Various	Refinery Tank Farm classified under 11 groups based on type of construction, type of seal, vapor pressure of the stored liquid and the regulatory applicability of different regulations.
EP	Fugitives	Ether Plant

Table 3: Emissions Units Covered By Part 2

Emission Unit	Emission Point/s	Emission Point Description
WWTP	Carbon canister locations[2]	Oily Sewer System, API/CPI separators, flash mix tank, spill diversion and equalization tanks, 2 flocculation tanks and dissolved nitrogen floatation (DNF) system
	10-1	DNF Oil Recovery System and Vapor Combustion Unit (VCU)
	No emission points	Secondary and tertiary treatment equipment (downstream of DNF), 1st and 2nd stage activated sludge, sand filtration and assorted sumps and equipment
GDF	N/A	Gasoline dispensing facility
MVR	15-1 and 15-2	Marine piers 2 and 3 loading area
CU	21-1	Crude Unit, Atmospheric heater 21-H-701, and vacuum heater 21-H-2
	21-1 or 28-1 or 28-2	Crude coker gasoline Merox treater
	28-1 or 28-2	SWS hydrogen sulfide stripping vessel, 21-C-302
FCU	22-1	Fluid coke handling and storage facility
	22-2	Fluid Coking Unit (FCU), FCU start up heater 22-H-1, CO Boiler (22-H-3), wet gas scrubber and SNCR
	22-3	Back up incinerator 22-H-4
	22-4	FCU Selas Steam Superheater
FCCU	23-1	FCCU start up heaters 23-H-1A and 1B, FCCU, CO Boiler (22-H-3), wet gas scrubber, alky merox spent air, and poly merox spent air
GP	No emission Points	Refinery gas plant
RFG2K	25-4 and 25-5	CNHT reactor charge heater 25-H-401, CNHT reboiler heater 25-H-402, CHNT unit, reformer, butamer unit
ALKY	No emission	Aklylation unit

[2] Carbon canisters are located at various parts of the oily sewer system and the primary treatment plant. The details of the locations are described in Section A of the accompanying review memorandum.

Emission Unit	Emission Point/s	Emission Point Description
	Points	
POLY	No emission Points	Polymerization unit
SRA	28-1 and 28-2	Sulfur recovery area inclusive of 2 Claus sulfur recovery units (SRU I and SRU II), Shell Claus Offgas Treatment Units I (SCOT I and II)
HP	37-1A and 37-1B	Hydrogen plant and reformer heater 37-H-1 A/B
MP	41-1 and 41-2	This unit has been shut down with no foreseeable plan to restart
CCR	42-1 and 42-2	CCR reformer unit, platform heater 42-H-1,2,3 and CCR reboiler 42-H-7
Utilities	45-1 and 45-2	Refinery flare system, spent caustic stripper and RFG2K cooling tower
Facility wide		See Condition 3 - Table 1 (Specific Conditions)

Table 4: Emissions Units Covered By Part 3

Emission Units		Emission Unit Description
DCPP	80-1	Boiler 1 (618 mmBTU/hr input, natural gas and desulfurized refinery fuel gas fired)
	80-2	Boiler 2 (716 mmBTU/hr input, natural gas and desulfurized refinery fuel gas fired)
	80-3	Boiler 3 (618 mmBTU/hr input, syngas, natural gas, and desulfurized refinery fuel gas fired)
	80-4	Boiler 4 (737 mmBTU/hr input, desulfurized refinery fuel gas fired)
Gas Plant	82	Texaco Gasifier 1 (235 ton/hr synthesis gas from both Gasifiers 1 and 2)
	82	Quench (gas cooler) for Gasifier 1
	82	Texaco Gasifier 2 (235 ton/hr synthesis gas from both Gasifiers 1 and 2)
	82	Quench (gas cooler) for Gasifier 2
	82	Amine Acid Gas Removal system
	82	Syngas Flare
	50	Three-Cell Linear Mechanical Draft Evaporative Cooler (gas flow of 3,000,000 ACFM, cooling water flow of 30,000 gallons per minute)
CCU	84	CCU1 & CCU2 - Each, one Gas Turbine (LHV input of 824.7 mmBTU/hr, HHV input of 878.4 mmBTU/hr, syngas or low sulfur diesel fuel fired)
	84	Duct Burner (215 mmBTU/hr, HHV of 215 mmBTU/hr, natural gas fired, one each, CCU1 & CCU2)
	84	Heat Recovery Steam Generator (one each, CCU1 & CCU2)

Emission Units		Emission Unit Description
	84	Electric Generator (90 MW nominal, one each, CCU1 & CCU2)

INSIGNIFICANT ACTIVITIES

Insignificant activities are included under Part 2 of this permit.

CURRENT 7 DE Admin. Code 1102 PERMITS

Table 5: 7 DE Admin. Code 1102 Permits Covered By Part 1

7 **DE Admin.** Code 1102 Permit	Unit Description
APC-82/0633-OPERATION issued February 8, 1985	Heater Unit 29-H-101
APC-81/0790-OPERATION issued June 17, 1981	Heater Unit 29-H-2
APC-81/0791-OPERATION issued June 17, 1981	Heater Unit 29-H-3
APC-81/0792-OPERATION issued June 17, 1981	Heater Unit 29-H-4
APC-81/0793-OPERATION issued June 17, 1981	Heater Unit 29-H-5
APC-81/0794-OPERATION issued June 17, 1981	Heater Unit 29-H-6
APC-81/0795-OPERATION issued June 17, 1981	Heater Unit 29-H-7
APC-81/0796-OPERATION issued June 17, 1981	Heater Unit 29-H-8
APC-81/0797-OPERATION issued June 17, 1981	Heater Unit 29-H-9
APC-81/0873-OPERATION issued August 21, 1981	Hydrodesulfurizer Train I
APC-81/0874-OPERATION issued August 21, 1981	Hydrodesulfurizer Train II
APC-81/0875-OPERATION issued August 21, 1981	Hydrodesulfurizer Train III
APC-81/0876-OPERATION issued August 21, 1981	Hydrodesulfurizer Train IV
APC-81/0877-OPERATION issued August 21, 1981	Hydrodesulfurizer Train V
APC-81/0832-OPERATION (Amendment 1)(HON) issued October 23, 1997	Benzene Loading Facility
APC-81/0833-OPERATION issued February 24, 1982	Aromatics Fractionation and Storage Facility
APC-82/0979-OPERATION issued September 16, 1982	Nitrogen Grade Toluene Facility
APC-81/0802-OPERATION issued June 17, 1981	Heater Unit 32-H-101
APC-81/0805-OPERATION issued June 17, 1981	Heater Unit 33-H-1
APC-81/0806-OPERATION issued June 17, 1981	Heater Unit 33-H-2
APC-81/0822-OPERATION (Amendment 1) issued June 12, 1992	Olefins Plant
APC-81/0808-OPERATION issued June 17, 1981	Heater Unit 134-H-101
APC-81/0966-OPERATION issued September 9, 1981	Hydrocracker Unit and Process Heaters 36-H-1, 36-H-2, and 36-H-3
APC-80/0869-OPERATION (Amendment 5)(VOC RACT)(NSPS) issued November 4, 1999	Intermediate Product Tank Farm
APC-80/0869-OPERATION (Amendment 4)(VOC RACT)(NSPS) issued April 12, 1996	Intermediate Product Tank Farm
APC-80/0870-OPERATION (Amendment 3)(VOC	Crude Oil Tank Farm

7 **DE Admin.** Code 1102 Permit	Unit Description
RACT)(NSPS) issued March 29, 2000	
APC-80/0870-OPERATION (Amendment 2)(VOC RACT)(NSPS) issued October 12, 1994	Crude Oil Tank Farm
APC-81/0120-OPERATION (Amendment 2)(RACT) issued November 6, 1996	Sour Water Treatment Crude Unit
APC-80/0868-OPERATION issued April 30, 1980	Product Tank Farm
APC-80/0868-CONSTRUCTION/OPERATION (NSPS)(RACT)(MACT) dated March 29, 2006	Ethanol Blending Project
APC-91/0553-OPERATION (RACT)(MACT) issued January 30, 1995	Ether Plant

Table 6: 7 DE Admin. Code 1102 Permits Covered By Part 2

7 **DE Admin.** Code 1102 Permit	Unit Description
APC-81/283 OPERATION issued January 14, 1981	Oil Recovery System
APC-81/1008 OPERATION (Amendment 3)(NESHAP) issued October 31, 2000	API/CPI Separators
APC-81/1008-CONSTRUCTION/OPERATION (Amendment 4)(NESHAP) issued February 22, 2001	API/CPI Separators
APC-81/1009 OPERATION (Amendment 2)(NESHAP) issued November 8,1999	Equalization Tanks and Spill Diversion Tank
APC-81/1009 OPERATION dated June 17, 1981	Two second stage clarifiers and 2 second stage aeration tanks[3]
APC-93/0350 CONSTRUCTION/OPERATION (Amendment 1)(NESHAP) issued on June 25, 2001	Oily Water Sewer System
APC-94/0710-OPERATION (NESHAP)(NOx RACT) issued April 14, 1998	VCU
APC-95/0862-OPERATION (Stage I) issued April 28, 1995	Dual point Stage I Vapor Recovery System
APC-95/0863-OPERATION (Stage II) issued April 28, 1995	Healy Stage II Vapor Recovery System
APC-95/0471-OPERATION (Amendment 2)(MACT)(RACT) issued May 3, 2002	Marine Vapor Recovery System
APC-81/0828 (A1)-OPERATION (Amendment 1) issued June 29, 2007	Crude Unit
APC-95/0570-OPERATION (Amendment 3)(NSPS) issued February 20, 2009	Crude Unit Atmospheric Heater 21-H-701
APC-81/0784-OPERATION (Amendment 2)(NOx RACT) issued February 20, 2009	Vacuum Tower Heater

[3] APC-81/1009 dated June 17, 1981 has 9 uncovered tanks listed in Appendix "A" of that permit. Of these 9 tanks, the 2 equalization tanks, 1 flocculator tank, 1 flash mix tank and 1 floatation clarifier have been included in subsequent NESHAP permits. Therefore the applicability of APC-81/1009 dated June 17, 1981 is restricted to the 2 second stage clarifiers and 2 second stage aeration tanks.

7 **DE Admin.** Code 1102 Permit	Unit Description
APC-81/0963-OPERATION issued August 12, 1981	coker Merox Plant
APC-81/0785-OPERATION issued June 17, 1981	various heaters
APC-81/0829-OPERATION (Amendment 7) issued June 4, 2008	Fluid Coker Unit, FCU Carbon Monoxide Boiler, Wet Gas Scrubber, and Selective Non-Catalytic Reduction System
APC-82/1209-OPERATION (Amendment 3) issued May 2, 2005	Coke and Flux Handling/Storage Facility
APC-82/0981-OPERATION (Amendment 7)(NSPS) issued June 30, 2008	Fluid Catalytic Cracking Unit (FCCU), FCCU Carbon Monoxide Boiler, and Wet Gas Scrubber Plus
APC-81/0827-OPERATION (Amendment 1)(RACT)(NSPS) issued January 30, 1995	Alkylation Merox Unit-Merox Treater
APC-98/0522-OPERATION (RACT)(NSPS) issued June 18, 2002	CHNT Heaters
APC-98/0523-OPERATION (NSPS)(RACT)(NESHAP) issued March 11, 2002	CNHT Unit, Butamer Unit, Alkylation Unit and cooling tower
APC 81/0825-OPERATION issued June 17, 1981	Catalytic Reformer Unit
APC 82/0593-OPERATION issued March 31, 1982	Polymerization Merox Plant
APC-81/0826-OPERATION (Amendment 2) issued August 22, 1991	Alkylation and Polymerization Units
APC-98/0264-CONSTRUCTION/OPERATION (Amendment 7)(NSPS) issued June 18, 2008	Sulfur Recovery Area and sulfur pit vapor recovery rerouting project
APC-81/0965-OPERATION issued September 9, 1981	Hydrogen Plant; and for the
APC-81/0965-OPERATION (Amendment 1)(VOC RACT) issued April 7, 2003	Hydrogen Plant Replacement of Low Temperature Shift Reactor Catalyst
APC-82/073-OPERATION issued February 8, 1985	CCR Reformer and Heater 42-H-1,2,3;
APC-82/0073-OPERATION (Amendment 1)(MACT) issued August 16, 2005	CCR Reformer and Hydrochloric Acid Wet Gas Scrubber
APC-82/0632-OPERATION issued February 8, 1985	CCR Reformer Reboiler Heater 42-H-7
APC-81/0830-OPERATION issued July 30, 1981	Flare System
APC-95/0381-OPERATION issued May 13, 1996	Spent Caustic Stripper
APC-2005/0197-OPERATION (RACT)(MACT)(NSPS) issued June 27, 2008	Tier II Gasoline Project

Table 7: 7 DE Admin. Code 1102 Permits Covered By Part 3

7 **DE Admin.** Code 1102 Permit	Unit Description
APC-90/0288-OPERATION (Amendment 9) - Boiler 1 issued May 26, 2009	Boiler 1
APC-90/0289-OPERATION (Amendment 7) - Boiler 2 issued may 26, 2009	Boiler 2

7 **DE Admin.** Code 1102 Permit	Unit Description
APC-90/0290-OPERATION (Amendment 8) - Boiler 3 issued may 26, 2009	Boiler 3
APC-90/0288-OPERATION (Amendment 6) issued December 16, 2008.	Boiler 1
APC-90/0289-OPERATION (Amendment 7) issued December 16, 2008	Boiler 2
APC-90/0290-OPERATION (Amendment 6) issued December 16, 2008.	Boiler 3
APC-90/0291-OPERATION (Amendment 1) issued December 16, 2008.	Boiler 4
APC-97/0503-OPERATION (Amendment 5)(LAER)(NSPS) issued December 16, 2008	Two combined cycle units, two duct burners, two heat recovery steam generators, two electric generators,
APC-90/0291-OPERATION (Amendment 2)-Boiler #4 issued May 26, 2009	Boiler 4
APC-97/0504-OPERATION issued August 6, 2003	Gasifiers #1 & #2, two gas coolers, amine acid gas removal system, syngas flare - Unit 82, One 3-cell linear mechanical draft evaporative cooler – Emission Unit 50
APC-97/0503-OPERATION (Amendment 7) (LAER)(NSPS) issued July 23, 2009	Two combined cycle units, two duct burners, two heat recovery steam generators, two electric generators – Emission Unit 84.
AQM-003/00016-CAIR issued May 27, 2008	DCPP4 (Boiler No. 4)
AQM-2009/0089 (Amendment 1) issued May 26, 2009	4 Package Boilers

III. Discussion on the Proposed Significant Permit Modification:

The main drivers behind this proposed significant permit modification are as follows:

- DNREC has proposed a modification to **7 DE Admin Code 1142** that will allow implementation of a NOx cap. This permit application was intended to incorporate conditions that that would allow compliance with the regulation as it is anticipated to be finalized.
- Incorporating the applicable requirements applicable to the facility following the issuance of recently issued permits pursuant to **7 DE Admin Code 1102**[4]**.**

  In 2009, Delaware promulgated Section 2.0 of **7 DE Admin Code 1142**, Control of NO_x Emissions from Industrial Boilers and Process Heaters at Petroleum Refineries. The purpose of that regulation was to reduce NOx emissions from large industrial boilers and process heaters that are located at petroleum refineries. Implementing Section 2.0 of this regulation would reduce NOx emissions from

[4] These applicable requirements are the result of permits issued to the facility after the issuance date of the most recent TV permit revision, i.e. A**dministrative Permit Modifications** to **Permit: AQM-003/00016 – Part 1 Renewal 1 Revision 4**, **Permit: AQM-003/00016 – Part 2 Revision 4**, and **Permit: AQM-003/00016 – Part 3 Renewal 1 Revision 4** all dated July 22, 2010.

the affected units, which were expected to contribute to attainment and maintenance of the 8-hour ozone standard, and improvement of the ambient air quality in both Delaware and the entire NAA. Section 2.0 of **7 DE Admin Code 1142** covers nine (9) emission units at the Delaware City Refinery, and imposes compliance dates between 2007 and 2012, depending on the particular emission unit. Reductions attributable to Section 2.0 of **7 DE Admin Code 1142** from covered emission units with compliance dates after 2002 (i.e., the base year for the 0.08 ppm ozone standard), and before the end of 2009 (i.e., the last full ozone season prior to the attainment date) have been relied upon in Delaware's 2007 ozone state implementation plan (SIP). Specifically, this includes DCPP Boilers 1 and 2 and the Crude Unit Vacuum[5]. Other units covered by **7 DE Admin Code 1142** include the FCU COB, DCPP Boilers 3 and 4, the process heater for the steam-methane reformer hydrogen plant and the continuous catalyst regenerator reformer. **7 DE Admin Code 1142** prescribed future applicable compliance dates for these remaining units. However, when DCRC acquired the DCR from Valero in May 2010, its plans for the future operation of the refinery did not include the upgrade of these affected units. Instead, DCRC proposed the establishment of a facility wide NOx cap to attain the same SIP projected goals. The DCRC Agreement accomplishes these objectives in the following manner:

- It establishes an initial NOx cap of 2525 TPY evaluated over each 12 consecutive month rolling period commencing with the 12-month rolling period comprised by calendar year 2011.
- It reduces the NOx cap to 2225 TPY evaluated over each 12 consecutive month rolling period commencing with the 12-month rolling period beginning on 12.31.2013 and ending on 12.31.2014.
- It further reduces the NOx cap to 1650 TPY evaluated over each 12 consecutive month rolling period commencing with the 12-month rolling period beginning on 12.31.2014 and ending on 12.31.2015.
- Finally, in consideration of nitrogen dioxide (NO_2) also being an attainment pollutant, in accordance with applicable PSD requirements under the CAA and **7 DE Admin Code 1125**, it provided a vehicle to establish a NO_2 PAL as discussed further under the section on technical discussion.

In this TV permit application for a significant permit modification, DCRC has made proposals to eliminate individual NOx emission limitations or operational requirements that relate to a NOx limit for specific sources at the refinery. Pursuant to the requirements in Paragraph 12 of the DCRC Agreement, DAQ has used the following criteria to determine whether an individual NOx emission limitation or operational requirement should be retained:

1. Criterion a: The limitation or requirement is specifically required for an emission source at the refinery by an applicable federal NSPS promulgated at 40 CFR Part 60, or MACT requirement promulgated at 40 CFR Part 61 or Part 63.
2. Criterion b: The limitation or requirement was imposed upon the source as a requirement of New Source Review for NOx emissions, applicable to the source through a prior permitting determination.

[5] Additionally, a NOx emission limitation imposed by a 2008 consent agreement on the Delaware City Refinery Fluid Catalytic Cracking Unit Carbon Monoxide boiler was relied upon in Delaware's' 2007 ozone SIP.

3. Criterion c: The limitation or requirement was imposed upon the source to avoid applicability of New Source Review for NOx emissions, specified for the source through a prior permitting determination.
4. Criterion d: The limitation or requirement was incorporated into the Delaware SIP as a regulation expressly promulgated to achieve NOx emission reductions required under Title I of the CAA.
5. Criterion e: Relaxation of the limit or requirement would result in a modeled exceedance by that source of an AAQS or an increment violation.

Table 8 shows a list of all NOx emission units to be covered under the facility-wide NOx cap, the emission point and the relevant part of the TV permit covering that specific emissions unit.

Table 8: NOx Emissions Units Covered by Facility-wide NOx Cap

NOx Cap Emissions Unit	Emission Point ID	Relevant TV Part
WWTP VCU	10-1	2
MVR TO	15-1 and 15-2	2
ATH	21-1	2
VTH	21-1	2
FCU, FCU COB and WGS	22-2, 22-3 and 22-4	2
FCCU, FCCU COB and WGS	23-1	2
CNHT feed heater	25-4	2
CNHT reboiler heater	25-5	2
SRU I – SCOT II	28-2	2
SRU II – SCOT 1	28-1	2
CHU 29-H-101	29-1	1
CHU 29-H-2	29-2	1
CHU 29-H-3	29-2	1
CHU 29-H-4	29-3	1
CHU 29-H-5	29-4	1
CHU 29-H-6	29-4	1
CHU 29-H-7	29-3	1
CHU 29-H-8	29-1	1
CHU 29-H-9	29-2	1
Tetra Unit 32-H-101	32-1	1
SHU start up heater 33-H-1	33-1	1
SHU reboiler heater 33-H-2	33-2	1
OP reboiler heater 134-H-101	34-1	1
HC feed heater 36-H-1	36-1	1
HC vacuum reboiler 36-H-2	36-2	1
HC fractionator reboiler 36-H-3	36-2	1
SMR HP 37-H-1A/B	37-1A/B	2
FES flare	40-1	1
CCR charge heater 42-H-1,2,3	42-1	2
CCR reboiler heater 42-H-7	42-2	2
North flare	45-1	2
South flare	45-2	2
Boiler 1	80-1	3
Boiler 2	80-1	3
Boiler 3	80-1	3

NOx Cap Emissions Unit	Emission Point ID	Relevant TV Part
Boiler 4	80-1	3
Syngas flare	82-1	3
CCU I	84-1	3
CCU II	84-2	3

Assessment of Baseline NOx Emissions:
To ensure that the facility-wide NOx cap does indeed provide acceptable reductions that can be incorporated into a modified TV permit, it is necessary for DAQ to first verify the baseline NOx emissions for the facility. The following section provides the supporting information related to the calculation of the baseline actual NO_2 emissions rate of 2,636 tons per year, calculated in accordance with 40 C.F.R. §52.21(aa)(6). The baseline was created by determining the average actual NO_2[6] emissions for each emission source during a representative 24 consecutive month period in the preceding 10 years. The actual emission levels for sources were adjusted, where appropriate, to be consistent with any enforceable limits. The emission baseline was developed using actual emission inventory and operating information reported to DNREC for the period. To calculate the baseline, actual NO_2 emissions were adjusted consistent with the requirements of 40 CFR §52.21(b)(48). Specifically, records were reviewed to determine whether downward adjustments were necessary to exclude any emissions that occurred while the NOx Cap units were operating above (1) an emission limitation that was legally enforceable during the consecutive 24-month period or (2) any emission limitation initially promulgated or effective after the commencement of the selected baseline period and with which the NOx Cap emission units must currently comply. As prescribed by 40 CFR §52.21(b)(48), DCRC examined the past 10-year period immediately preceding this permit application to select a consecutive 24-month period for purposes of calculating baseline actual emissions. Based on a review of the previous 10-year period, DCRC selected a baseline period of March 2006 through February 2008 as representative of normal operations. DAQ concurs with this analysis because of the following reasons:

- Controls were installed on two of DCR's largest emissions units, i.e., the FCU and FCCU in 2006.
- Prior to 2006, operation of the FCCU was found to be in violation of **7 DE Admin Code 1125**.[7]
- In February 2008, the DCR experienced a steam emergency that triggered a near total shut down of the DCR. In the aftermath of this incident, despite refinery operations being somewhat restored, the DCR never regained its design operating potential leading ultimately to its total shut down in November 2009.

Discussion on Existing Unit Specific Emissions Limits:
Historically, many of the **7 DE Admin Code 1125** permits for the emissions units listed in table 8 had unit specific emissions limits and operational limitations incorporated in them which were subsequently incorporated into the 3 parts of the facility's TV permit. Because the DCRC Agreement provides a mechanism to develop a facility-wide NOx cap, DCRC has sought the deletion of several of these units' specific emissions limits and operational limitations. Table 9 below provides DAQ's evaluation of these units' specific emissions limits and operational limitations. Column 1 describes the NOx cap emission unit,

[6] Consistent with historical practice at the refinery, NO_2 emissions are conservatively assumed equal to reported NO_x emissions. The historical basis for emissions estimation at the facility is to assume all emissions are NO_2, i.e. a molecular weight of 46 lb/mol is used to calculate tons emitted. DCRC proposes to use this convention consistently for both baseline actual emission calculations and compliance demonstration with the PAL NO2 limitation.

[7] See Notice of Violation issued by the Department to The Premcor Refining group Inc. on December 16, 2004 for continuing to operate the FCCU in a manner that caused an increase in the unit's NOx emissions prior to obtaining a NSR permit pursuant to the requirements of **7 DE Admin Code 1125.**

Column 2 provides the citation of the existing TV permit condition, Column 3 shows the existing permit condition, Column 4 describes DCRC's proposal, and Column 5 provides DAQ's determination and comments. Columns 2 and 3 are obviously left blank where DCRC has proposed new language for new additions.

Table 9: DAQ's Evaluation of Unit Specific Emissions Limits and Operational Limitations

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
29-H-101	Part 1, a.3.i.B.	For Units 29-H-101 and Units 29-H-2 through 29-H-9: NO_X emissions shall not exceed those achieved through an annual tune up performed by qualified personnel. *[Reference: 7* ***DE Admin. Code*** *1112, Section 3.3.2 dated 11/24/93]*	Deletion of this requirement to perform an annual tune up of 29-H-101.	DAQ disagrees. DCRC has not provided adequate justification to delete what is an existing requirement thereby contravening the provisions of Paragraph 15 of the DCRC Agreement. Furthermore, this requirement does not impede DCRC's ability to comply with the facility-wide NOx cap. On the contrary, a tuned up unit will be more likely to minimize its NOx contribution thereby facilitating compliance with the facility-wide cap and will operate in conformity with good air pollution control practices.
29-H-1 through 29-H-9			Addition of a new Part 1 Condition: a.3.i.C. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
32-H-101			Addition of a new Part 1 Condition: bc.3.i.B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
33-H-2			Addition of a new Part 1 Condition: c.3.i.B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
134-H-101			Addition of a new Part 1 Condition: d.3.i.B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
36-H-1, 36-H-2 and 36-H-3			Addition of a new Part 1 Condition: e.3.i.C. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
40-1			Addition of new Part 1 Condition fi.1: Owner/Operator is permitted to emit pollutants from the flare so long as flare operations comply with the Visible Emission Standard and the Sulfur Dioxide Standard; and Part 1 Condition: fi.4. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ finds this issue to be moot because the FES has been emptied, is no longer operational, and is in the process of being decommissioned. Therefore, DAQ is deleting the requirements for this decommissioned emission unit.
WWTP VCU			Addition of a new Part 2 Condition: ac.3.i.B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NO_X)" in Condition 3, Table 1.j.	DAQ concurs.
MVR	Part 2, a.3.i.	NO_X emissions shall not	Deletion of this requirement because the NOx	DAQ concurs.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		exceed 61.3 lb/hour and 22.3 tons in any twelve consecutive months. *[Reference: Permit: APC-95/0471 (A2)]*	emissions from the MVR oxidizers will be included under the facility-wide NOx cap.	
CU	Part 2, c.1.i.A.	The throughput to the crude unit shall not exceed 191,100 BPD on a twelve month rolling average basis. *[Reference: APC-81/0828 (A1)]*	Deletion of this requirement because it is not based upon applicable federal or state limitations.	DAQ disagrees. The throughput limit on the crude unit was established as a benchmark from which future emissions changes could be assessed not just from the crude unit or for NOx emissions, but from all downstream unit operations and for all pollutants. This limit was established as part of the Department's review of Phase I of the PCUP and was extensively covered in AQM's analysis of the implications of debottlenecking the refinery by the installation of WGS controls on the FCU and FCCU and was put in place to avoid triggering NSR.[8] Following issuance of the PCUP Phase I permits, Premcor filed an appeal before the EAB which was subsequently settled between the parties when the permitted throughput limit was established.[9] Therefore deletion of the throughput limitation will contravene criterion c of Paragraph 12 of the DCRC Agreement.

[8] See Response Document Developed by the Air Quality Management (AQM) Section for Comments Received from the Premcor Refining Group Inc. regarding AQM's Draft Permits for Phase I of the Pollution Control Upgrade Project (PCUP) Following a Public Hearing Held on October 19 and October 20, 2004. The response document is dated November 15, 2004.
[9] See Stipulation Before the Environmental Appeals Board for the State of Delaware in the Matter of EAB No. 2004-04, EAB No. 2004-05 and EAB No. 2004-07 signed by John Hughes, DNREC Secretary, Valerie Csizmadia, DAG and Bart Cassidy, Esq. on behalf of Premcor.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
21-H-701 and 2-H-2	Part 2, c.1.i.B. and c.1.i.C.	The heat input to Unit 21-H-701 shall not exceed 490 mmBtu/hr on a twelve month rolling average basis and 530 mmBtu/hr on a twenty-four hour rolling average basis. *[Reference: Permit:APC-95/0570 (A 2)]*; and The heat input to 21-H-2 shall not exceed 249 mmBtu/hour on a 365 day rolling average basis. *[Reference: Permit:APC-81/0784]*	DCRC is requesting that the firing rate limits for the Crude Unit heaters be removed from the Permit because they are no longer relevant since both emissions units have unit specific emission limits for all pollutants.	DAQ concurs.
21-H-701	Part 2, c.4.i.A.	For 21-H-701: NO_X emissions shall not exceed 0.043 lb/mmBtu on a 3 hour rolling average and 92.3 tons in any rolling twelve month period. *[Reference: Permit:APC-95/0570 (A 2)]*B. For 21-H-2: NO_X emissions shall not Exceed 0.20 lb/mmBtu on a 24 hour rolling average. *[Reference: Permit: APC-81/0784 and* 7 ***DE Admin. Code*** *1112 Section 3.2(a) dated 11/24/93]*	DCRC has proposed deletion of this limit based on the following explanation: The 0.04 lb/MMBtu on a 3 hour rolling average NOx emission limit was established to comply with Delaware Regulation 1142 Section 2.3.4. Reg. 1142, however is to be revised to reflect that a NOx cap may be established in lieu of complying with specific NOx emission limitations established through Reg. 1142. To comply with Reg. 1142, Premcor chose to install selective catalytic reduction ("SCR") technology to the 21-H-2 and 21-H-701 common stack. Premcor voluntarily accepted the 20 lb/hr NOx limit on a 24 hour rolling average after the Department expressed concern that the application of SCR to the mixed effluent gases from these heaters offered an opportunity to achieve compliance with Reg. 1142's 0.04 lb/MMBtu limit "by dilution" of a higher concentration stream from one heater with a lower concentration stream from another. Because Reg. 1142 is to be revised to reflect that a NOx cap may be established in lieu of complying with specific NOx	DAQ agrees that the existing limits of 0.043 lb/mmBtu on a 3-hour rolling average and 92.3 TPY can be deleted because they are now obsolete. However, DAQ disagrees with DCRC's proposal to delete the new limits established by the most recent permit because deletion of these limits contravenes Criterion b of Paragraph 12 of the DCRC Agreement. DCRC's argument supporting the deletion of this limit is based only on the nexus between 7 **DE Admin Code 1142** and the fact that the DCRC Agreement provides a vehicle to establish a facility-wide NOx cap in lieu of complying with specific NOx emission limitations established through **7 DE Admin Code 1102**. This logic ignores the fact that the emission limits in question were established in 1996 as

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
			emission limitations established through Reg. 1142, there is no longer a need for this hourly emission limit or the corresponding tons per year limit.	a result of a NSR permitting exercise when the old oil-fired 21-H-2 heater was replaced[10]. Furthermore, when this emission unit was modified as part of the PCUP, it was again subject to review under NSR.[11] Finally, when 21-H-2 was to be upgraded to make it compliant with **7 DE Admin Code 1142**, this permit was again issued after review under PSD NSR as part of the larger UOP (Bin 1 Project).[12] The permit as issued here did not specify "LAER" in its permit number, because the emission limit of 0.04 lb/mmbtu was no longer representative of satisfying contemporary (*circa* 2008) LAER performance standards. Although the permit was reissued for the installation of a shared SCR system with 21-H-2, with emissions limits that coincidentally met the same performance as those specified by **DE Admin Code** 1142, DCRC's proposal does not, and should not be allowed to, negate all past NSR determinations.
21-H-701 and 2-H-2			For 21-H-701 and 21-H-2: NO_X emissions shall not exceed 0.20 lb/mmBtu on a 24 hour rolling average basis. *[Reference:* 7 ***DE Admin. Code*** *1112 Section 3.2.1 dated 11/24/93]*	DAQ disagrees. (See DAQ's response to the previous condition)

[10] See **7 DE Admin Code 1102** permit for the construction of Unit 21-H-701; **Permit:APC-95/0570 CONSTRUCTION (LAER)(NSPS)** dated 03.04. 1996.
[11] See **7 DE Admin Code 1102** permit for the modification of Unit 21-H-701; **Permit:APC-95/0570 CONSTRUCTION (Amendment 2)(LAER)(NSPS)** dated 11.30.2004.
[12] See **7 DE Admin Code 1102** permit for the modification of Unit 21-H-701; **Permit:APC-95/0570 CONSTRUCTION (Amendment 3)(NSPS)** dated 05.14.2008.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
FCU, FCU COB, SNCR and WGS	Part 2, da.1.i.G.2.	The Emission Standards in Condition 3 - Table 1.da.2 through da.10 below shall not apply during periods of planned start up and planned shut downs of the FCU provided the planned start up and shut down event does not exceed 116 hours. The Emission Standards shall apply to each planned start up or shut down event after the expiration of the 116 hour period. Planned start ups shall be considered a maximum of 116 hours preceding oil back into the unit. Planned shut downs shall be considered a maximum of 116 hour from feed out of the FCU. In lieu of the Emission Standards, the following Emission Standards shall apply during planned start ups and shut downs of the FCU: 2. NO_x – 207 lb/hour	DCRC has proposed deletion of the NOx limit	DAQ concurs.
FCU, FCU COB, SNCR and WGS	Da.4.C	NOx emissions from the FCU WGS shall not exceed 152 ppmvd @ 0 % oxygen on a 24 hour rolling average basis and 689.8 TPY. The Owner/Operator shall propose annual concentration based (365 day average) and mass emission (TPY) limits by July 27, 2008 based on	DCRC is requesting that the following individual NOx limitations associated with the Fluid Coking Unit (FCU), Unit 22 be removed from the relevant Title V Permit(s) for this emission unit. **Emission Unit** | **NOx Emission Limit or Related Emission/Operational Limit** | **Permit Reference**	DAQ disagrees. The Bin 1 project on the whole will result in 41.8 TPY reductions in NO_x emissions. However, this figure was based on the Company accepting a federally enforceable limitation on the FCU PTE at the existing permit limit of 689.8 TPY. Baseline FCU NO_x emissions were 674.

<table>
<tr><th>NOx Cap Emissions Unit</th><th>Existing TV Permit Part and Condition Citation</th><th>Existing TV Permit Condition</th><th>DCRC's Proposal</th><th>DAQ Determination and Comments</th></tr>
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<td>approximately 6 months of rolling 365-day data spanning the period November 27, 2007 through May 27, 2008 for AQM's review, approval and incorporation into this permit. [Reference APC-81/0829 (A7)]</td>
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<table>
<tr><td>FCU WGS</td><td>152 ppmvd @ 0% O2, 24-hr rolling average</td><td>AQM-003/00016 – Part 2 (Rev 4) Condition 3 – Table 1.da.4.i.C</td></tr>
<tr><td>FCU WGS</td><td>207 lb/hr, during planned startup and shutdown periods</td><td>AQM-003/00016 – Part 2 (Rev 4) Condition 3 – Table 1.da.1.i.G.2</td></tr>
<tr><td>FCU WGS</td><td>689.9 TPY</td><td>AQM-003/00016 – Part 2 (Rev 4) Condition 3 – Table 1.da.4.i.C</td></tr>
</table>
These limits are not based upon applicable federal or state limitations.
</td>
<td>TPY resulting in a net increase of 15.3 TPY, which by itself does not exceed the significance threshold of 25 TPY. However, because the FCU coke burn would have increased from a baseline level of 47.1 Mlb/hr to 60.9 Mlb/hr as a result of the Bin 1 project, the FCU's NO_x PTE was actually 780 TPY[13]. Therefore, absent a federally enforceable limitation on the FCU NO_x PTE, NA-NSR would have been triggered.

In accordance with the requirements of Section 1.8 of 7 DE Admin Code 1125:

Any stationary source that implements, for the purpose of gaining relief from Regulation 1125, Section 3, by any physical or operational limitation on the capacity of the source to emit a pollutant, including (but not limited to) air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design and the limitation or the effect it would have on</td>
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[13] See FCU NO_x PTE calculation in AQM's technical memorandum dated July 15, 2008.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				emissions is enforceable, not withstanding any emission limit specified elsewhere in the State of Delaware Regulations Governing th Control of Air Pollution. If a source petitions the Department for relief from any resulting limitation described above, the source is subject to review under Regulation 1125, Sections 2 and 3 as though construction had not yet commenced on the source or modification. Deletion of these limits will contravene Criterion b of Paragraph 12 of the DCRC Agreement.
FCCU, FCCU COB and WGS	Part 2, e.1.i.B.	Before the WGS + system is operational, except as provided in Operating Limitation J, the COB, Belco pre-scrubber, the amine-based Cansolv regenerative WGS, and the caustic polishing scrubber shall be operating properly at all times when the FCCU is operating. After the commencement of operation of the NO_X control system, except as provided in Operational Limitation J, the NO_X control system shall be operating properly at all times when the FCCU is operating.	DCRC has deleted the words 'Before the WGS + system is operational'.	DAQ concurs.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
FCCU, FCCU COB and WGS	Part 2, e.1.i.C.	Before the WGS + system is operational, during planned start ups of the FCCU, the FCCU COB and WGS shall be operating prior to introducing feed into the riser reactor of the FCCU. In the event of a planned shut down of the FCCU, the FCCU COB or the WGS, the Owner/Operator shall continue to operate the FCCU COB and WGS until there is no feed entering the riser reactor of the FCCU prior to commencing shut down of the FCCU COB and the WGS.After commencement of operation of the NO_x control system, during planned startups of the FCCU, the NO_x control system shall be operating prior to introducing feed into the riser reactor of the FCCU. In the event of a planned shutdown of the FCCU, the WGS or the NO_X control system, the Owner/Operator shall continue to operate the NO_x control system until there is no feed entering the riser reactor of the	DCRC has deleted the words 'Before the WGS + system is operational'	DAQ concurs. The requirement to install the WGS + system was according to the FCCU NOx Agreement with the previous owner (Valero). As part of the settlement agreement with Valero for past violations and pending enforcement actions, the Department terminated the FCCU NOx Agreement.[14]

[14] Administrative Order on Consent entered on May 28, 2010 between DNREC and The Premcor Refining Group Inc.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		FCCU prior to commencing shut down of the NO_X control system.		
FCCU, FCCU COB and WGS	Part 2, e.1.i.D.	Prior to May 1, 2009, in the event that the FCCU COB and/or the NO_X control system is shut down, operation of the FCCU shall be in accordance with Attachment B of this permit. On and after May 1, 2009, during periods of outages of any component of the NO_X control system, the Owner/Operator, at a minimum, must initiate a reduction in the feed rate to the FCCU by no later than 24 hours following the commencement of the outage. The Owner/Operator will reduce FCCU feed rate by 5,000 barrels per hour until the feed rate to the FCCU is 55,000 bpd.	DCRC has deleted the references to operation of the FCCU prior to may 1, 2009 which was the deadline for compliance with the requirement to complete construction of the WGS + system.	DAQ concurs. The requirement to install the WGS + system was according to the FCCU NOx Agreement with the previous owner (Premcor). As part of the settlement agreement with Valero for past violations and pending enforcement actions, the Department terminated the FCCU NOx Agreement.[15]
FCCU, FCCU COB and WGS	Part 2, e.1.i.H.	The Emission Standards in Condition 3 - Table 1.e.2 through e.9 below shall not apply during periods of planned shut down and planned start up of the FCCU for a period of time not to exceed 72 hours for each planned shut down and each	DCRC has proposed deletion of the NOx limit	DAQ concurs.

[15] Administrative Order on Consent entered on May 28, 2010 between DNREC and The Premcor Refining Group Inc.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		planned start up event. The planned shut down period shall begin when there is no feed entering the FCCU reaction section. The planned start up period shall begin when dry-out of the FCCU is commenced. The Emission Standards in Condition 3 - Table 1.e.2 through e.9 shall apply to each planned start up event after the expiration of the 72 hour period. In lieu of the Emission Standards, the following emission limitations shall apply during planned start ups and shut downs of the FCCU: 1. VOC – 9.5 lb/hr 2. NO_x – 360 lbs/hr 3. PM – 500 lbs/hr 4. SO_2 – 165 lbs/hr 5. CO – 860 lbs/hr		
FCCU, FCCU COB and WGS	Part 2, e.1.i.I.	I. In the event of an unplanned shutdown of the CO Boiler, the Owner/Operator shall as expeditiously as practicable but no later than 24 hours initiate promoted burn in the FCCU regenerator to control CO emissions in accordance	DCRC has proposed deleting the last sentence because the bypass system will be constructed as authorized by the construction permit,[16] and as part of the ongoing recommissioning and turnaround activity prior to the start up next year.	DAQ concurs.

[16] **Permit:APC-82/0981 CONSTRUCTION/OPERATION (Amendment 8)(NSPS)** dated 05.01.2009.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		with Condition 3, Table 1.e.5.i. Additionally the Owner/Operator shall expeditiously as practicable but no later than 24 hours utilize the flue gas bypass system to route the FCCU emissions stream through the NO_x control system.		
FCCU, FCCU COB and WGS	Part 2, e.1.i.J.	Except as provided in Operational Limitation D, this permit does not authorize emissions exceeding the limits set forth in Condition 3, Table 1.e.2 through e.9 including emissions during periods of any unplanned shutdown of the FCCU, or any unplanned shutdown or bypass of the FCCU COB, or the Belco prescrubber or WGS or the NO_X control system. Instead, in the event of any unplanned shutdown of the FCCU or any unplanned shutdown or bypass of the FCCU COB or Belco prescrubber or the WGS or NO_X control system, the Owner/Operator shall bear the burden of demonstrating to the Department's satisfaction that the Owner/Operator's continued operation of the FCCU should not subject the Owner/Operator to an enforcement action for noncompliance with emission limitations or operating	DCRC has proposed deletion of the references to "NOx control system".	DAQ concurs.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		standards included in this Permit or otherwise applicable to the facility under the State of Delaware "Regulations Governing the Control of Air Pollution." Such demonstration must at a minimum be supported by sufficient documentation and emissions data including all relevant emissions calculations, formulas, and any assumptions made thereof. The Department's evaluation shall consider, the specific circumstances of the event, including without limitation 1) the cause of, and the Owner/Operator's response to, the unplanned shutdown; 2) whether the Owner/Operator has taken all reasonable and prudent steps to abide by the emissions limit conditions; 3) whether the Owner/Operator has taken all reasonable and prudent steps to minimize the emissions associated with the plant; 4) the degree to which the Owner/Operator has reduced throughput to the FCCU, and the basis for such degree of reduction; 5) the estimated emissions associated with a complete shutdown of the FCCU; 6) whether Premcor had reviewed all prior similar		

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		causes of unplanned shutdowns and had taken all reasonable and prudent actions necessary to avoid future similar outages; and 7) the actual emissions during the period of the unplanned shutdown.		
FCCU, FCCU COB and WGS	Part 2, e.4.i.	Emission Standard: A. RESERVED B. Before the WGS+ system is operational, NO_X emissions from the FCCU WGS+ shall not exceed 118 ppmvd at 0% O_2 on a 7-day rolling average basis and 719.5 TPY on a 365-day rolling average basis. *[Reference APC-82/0981 (A7)]* C. After the commencement of operation of the NO_X control system, NO_X emissions shall not exceed 20 ppmvd @ 0% O_2 on a 365-day rolling average basis, 40 ppmvd @ 0% O_2 on a 7-day rolling average basis and 207 TPY on a 365-day rolling average basis. *[Reference APC-82/0981 (A7)]*	DCRC has proposed replacement of the existing emission standard with the following language: A. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j B. NO_X emissions shall not exceed 0.20 lb/mmBtu on a 24 hour rolling average basis. *[Reference:* 7 ***DE Admin. Code*** *1112 Section 3.2.1 dated 11/24/93]*	DAQ disagrees. In 2004, the Department issued NOVs to Motiva and Premcor when operational changes to the FCCU, purportedly done to make the FCCU compliant with the NSPS for CO emissions, caused the FCCU to experience a significant increase in NOx emissions. The Department initiated an enforcement action which culminated in the FCCU NOx Agreement (FNA) with Premcor being signed on July 6, 2006. The FNA provided a 2-step process to reduce NOx emissions from the FCCU. In the first step, also known as Interim Measures (Section II of the FNA), installation of low-NOx burners in the FCCU COB coupled with enhancements to the combustion process by means of CFD modeling were to result in NOx emissions not exceeding 620 to 738 TPY by no later than September 1, 2007. These improvements were completed and the reductions were made practically enforceable by DAQ when a permit was issued limiting FCCU NOx emission to 118 ppmvd at 0 % O_2 on a 7-day rolling average

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				and 719.5 TPY on a 365- day rolling average basis.[17] The second step was designed to provide additional NOx emissions reductions to 20 ppmvd @ o % O_2 on a 7-day rolling average basis and 202 TPY TPY on a 365- day rolling average basis.[18] The anticipated reductions attributable to the second step have not been realized because the FNA was terminated when the Department and Premcor settled all past violations. [19] Because the reductions realized by step 1 of the FNA were to gain relief from triggering NSR provisions the unit specific existing limits in the permit should be retained. Furthermore, because Premcor completed a FCCU NOx Demonstration Study as required by paragraph 21(a) of the federal CD, an additional limit of 98 ppmvd @ 0 % O_2 on a 365-day rolling average basis must also be included in the permit. DAQ had not incorporated this limit in an earlier permitting action because it had fully anticipated it to be subsumed under the reductions to have been realized under Step 2 of the FNA. Deletion of these limits will contravene Criterion b of Paragraph 12 of the DCRC Agreement.

[17] **Permit:APC-82/0981 OPERATION (Amendment 6)(NSPS) Addendum 1** dated October 1, 2007.
[18] **Permit:APC-82/0981 CONSTRUCTION/OPERATION (Amendment 8)(NSPS)** dated May 1, 2009.
[19] Administrative Order on Consent entered on May 28, 2010 between DNREC and The Premcor Refining Group Inc.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
Reformer and RFG 2K project, CNHT unit, Butamer Unit and Cooling Tower	Part 2, ga.1.i.A.	The heat inputs to 25-H-401 and 25-H-402 shall not exceed 107 mmBtu/hour and 78.7 mmBtu/hour respectively, both on a twenty-four hour block average (i.e., calendar day) basis. *[Reference: APC-98/0522]*	DCRC has requested deletion of the heat input limitations because they are not based upon applicable federal or state requirements, but rather they were based on design data provided by Motiva in a letter to the Department dated October 21, 1998.	DAQ disagrees. The heat input limits are necessary to ensure compliance with the NOx emission limits in the existing permit which were established to avoid triggering NSR. Deletion of these limits will contravene Criterion c of Paragraph 12 of the DCRC Agreement.
Reformer and RFG 2K project, CNHT unit, Butamer Unit and Cooling Tower	Part 2, ga.4.	Nitrogen Oxides (NO_X): i. Emission Standard:*[Reference: APC-98/0522]* A.For 25-H-401: 13.7 TPY on a rolling twelve month basis B. For 25-H-402: 10.1TPYon a rolling twelve month basis C. For 25-H-401 and 25-H-402: 0.029 lb/mmBtu.	DCRC has requested deletion of this limit and replacing it with the following: Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j. B. For 25-H-401 and 25-H-402: NO_X emissions shall not exceed 0.20 lb/mmBtu on a 24 hour rolling average basis. *[Reference: 7 **DE Admin. Code** 1112 Section 3.2.1 dated 11/24/93]*	DAQ disagrees. These NOx limits were expressly incorporated in the**7 DE Admin Code 1102** permit[20] to avoid NSR. Therefore deletion of these limits will contravene Criterion c of Paragraph 12 of the DCRC Agreement.
SRA	Part 2, j.4.i.	NO_X emissions shall not exceed 7.0 lb/hr in each SCOT stack and 51.9 TPY combined from both SCOT stacks. *[Reference: APC-98/0264(A7)]*	DCRC has requested deletion of this condition and replacing it with the following: A. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j B. NOx emissions shall not exceed those achieved through an annual tune up performed by qualified personnel. *[Reference: 7 **DE Admin. Code** 1112 Section 3.3.2 dated 11/24/93]* B. NOx emissions shall not exceed those achieved through an annual tune up performed by qualified personnel. *[Reference: 7 **DE Admin. Code** 1112 Section 3.3.2 dated 11/24/93]*	DAQ concurs.
SMR - HP	Part 2, k.4.i.	NO_X emissions shall not	DCRC has proposed the addition of the following	DAQ concurs.

[20] See Condition 2.2 of **Permit: APC-98/0522-OPERATION (RACT)(NSPS)** dated June 18, 2002.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		exceed 0.20 lb/mmBtu on a 24 hour rolling average basis. *[Reference:* 7 ***DE Admin. Code*** *1112 Section 3.2.1 dated 11/24/93]*	language: Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j	
CCR	Part 2, m.3.i.	For 42-H-1,2,3: NO_X emissions shall not exceed 0.20 lb/mmBtu on a 24 hour rolling average basis	DCRC has proposed the addition of the following language: B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j C. For 42-H-7: NO_X emissions shall not exceed those achieved by the installation of either low excess air and low NO_X burner technology or flue gas recirculation technology. *[Reference:* 7 ***DE Admin. Code*** *1112, Section 3.3.1 dated 11/24/93]*	DAQ concurs
Refinery Utilities	Part 2, n.		DCRC has proposed addition of the following new conditions: i. Emission Standards A. Owner/Operator is permitted to emit pollutants from the flare so long as flare operations comply with the Operational Limitations. B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j	DAQ disagrees with the proposed emission standard A. Delaware law at 7 Del. C. sec. 6003(b) requires a person to obtain a permit from DNREC before emitting an air pollutant. A facility is required to list the pollutants it intends to emit in its permit application form, so that DNREC may evaluate the impacts of any emissions on the environment. Generally, it is known which types and sources of pollution will be emitted from any emission point, and an applicant is required to seek a permit to emit those pollutants. The refinery blowdown system and flare are different from ordinary air pollution control equipment. The flare is intended to be used primarily as a control device to safely combust flammable gases and thus prevent

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				overpressurization of upstream process units that handle and process combustible liquids and gases. Flares also serve as a pollution control devices, to the extent that when a malfunction occurs at the Refinery, hydrocarbons and other flammable gases are incinerated, in order to reduce the health and safety impacts from the flare. It is intended to be a control device of last resort, as it results in sudden emissions of what can be vast amounts of pollutants; however, it is a better alternative than simply venting those pollutants directly into the atmosphere. Thus, the flare burns the gasses and reduces the amounts and potential impacts of pollutants emitted, but nonetheless results in an unanticipatable amount of emissions of air pollution. Since it is likely impossible to know in advance what systems at the refinery will malfunction, and for what duration of time, then it is likely not possible to quantify in advance what types and quantities will be emitted from the flare. In order to avoid violating 7 Del. C. Sec. 6003 (b), emissions control devices, require permits 1) for their installation and operation and 2) for pollutants to be emitted. Nonetheless, since the refinery did not specify what pollutants would be emitted from the flare (because it likely could not accurately do so, it

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				neither requested nor acquired a permit to emit any particular pollutants, and thus, the permit it acquired was only for the installation and ability to operate it. The permit does not specify that any amount or quantity of air pollution may be emitted from it. Thus, the permit to install and operate the flare does not give what would be an unquantifiable permission to emit any quantity and duration of pollution, as the refinery asks DNREC to interpret the permit. Because DNREC was cognizant of the necessity for the refinery to have a properly operating safety blowdown system and flare to safely combust and dispose of flammable hydrocarbon and other gases that could potentially be released during refinery operations, DNREC issued a permit to install and operate the flare system to allow it to safely dispose of gases that are vented to it. However, DNREC was not provided with sufficient information and was not asked to permit any quantity of specific emissions. Consequently, any and all emissions from the flare are emissions of unpermitted quantities of air pollution. In fact, 7 del. Admin. Code 1102, prevents DNREC from issuing a permit that could allow the emissions of sufficient quantities of pollution to "bust the SIP." Thus, DNREC could not lawfully permit the

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				flare in the manner that the Refinery requests. The Refinery requests its permit to be interpreted as blanket permission to send whatever gases it wants to the flare, any time it wants to vent them, without there being any violation of the statute that requires the impacts of emissions to be considered before a permit can be issued. Should the refinery be maintained and operated in a manner that equipment does not malfunction, then no pollutants would be emitted from the flare, and no violation would occur for emitting pollution. Should the refinery's equipment malfunction and the flare need to be used, then DNREC assesses a penalty based on the amount and type of pollution emitted from the flare. The lack of permitted emissions is incentive for the refinery to undertake effective maintenance and operational safeguards so that it does not release unpermitted emissions caused by its equipment malfunctions and incentive for the Refinery not to incinerate anything it does not have to incinerate. Should the permit be interpreted differently, all impetus for the Refinery to use the emissions control device in the manner it is intended (which is to be a last resort method of incinerating gases to reduce the amount of pollution emitted) would be negated and the permit could potentially

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				violate Regulation 1102. DAQ concurs that NOx emissions from the flare will be a part of the overall facility-wide NOx cap.
Boiler 1, 2, 3 and 4	Part 3, a.2.i.E.	Except during periods of startup and shutdown, the burner steam injection and flue gas recirculation systems in Boiler 2 shall be working in a manner consistent with maintaining 0.04 lb/MMBtu NO_X on a 24 hour rolling average.	DCRC has proposed deletion of this condition.	DAQ disagrees. Boiler 2 was upgraded in 2004 as a consequence of a settlement agreement[21] resolving a NSR violation. This NSR violation resulted from the failure of Motiva, the DCR owner in 2001, to shut down Boiler 2 permanently as was required at that time to make the anticipated NOx reductions from the Repowering Project real and practically enforceable. Paragraph 11 of the settlement order describes the release afforded to Motiva and its successors in interest from any and all liability for the continued operation of Boiler 2. Therefore, deletion of this condition will contravene Criterion c of Paragraph 12 of the DCRC Agreement.
Boiler 1, 2, 3 and 4			DCRC has proposed the addition of the following language: B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j	DAQ concurs.
Boiler 1, 2, 3 and 4	Part 3, a.5.i.B.	B. The Owner/Operator shall not cause or allow the emission of NO_X in excess of the following baseline emission levels for the boilers:	DCRC has proposed deletion of this condition.	DAQ concurs with respect to the limits on boilers 1 and 3. However, DAQ disagrees with respect to Boiler 2 for the reasons described in DAQ's response to existing Part 3 Condition a.2.i.E. above because deletion of

[21] Administrative Penalty Assessment and Secretary's Order No. 2001-A-0053 dated December 31, 2001.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		1. Boiler 80-1:541.4 TPY 2. Boiler 80-2:125.4 TPY 3. Boiler 80-3:541.4 TPY		this condition will contravene Criterion c of Paragraph 12 of the DCRC Agreement.
Boiler 1, 2, 3 and 4	Part 3, a.5.i.C.2.	0.04 lb/mmBtu for Boiler 80-2.	DCRC has proposed deletion of this condition.	DAQ disagrees with respect to Boiler 2 for the reasons described in DAQ's response to existing Part 3 Condition a.2.i.E. above.
Syngas flare			DCRC has proposed the addition of the following language: B. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j	DAQ concurs.
CCUs	Part 3, d.4.i.B.	The Owner/Operator shall not cause or allow the emission of NO_X in excess of 360 TPY from each CCU.	DCRC has proposed replacing this condition with the following language: A. Comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j	DAQ disagrees. The emission limits for the CCUs were incorporated as the result of past non-attainment NSR review establishing a level of control meeting LAER requirements. Therefore, deletion of this condition will contravene Criterion b of Paragraph 12 of the DCRC Agreement.
Boilers and CCUs	Part 3, f.4.	Emission Standards: *[Reference APC-90/0288 (A5), APC-90/0289 (A6), APC-90/0290 (A5) and APC-97/0503 (A3)]* The Owner/Operator shall not cause or allow the emission of NO_X in excess of 1,261 TPY from the CCUs (Emission Units 84-1 and 84-2) and Boilers 80-1, 80-2 and 80-3, combined on a rolling twelve (12) month basis. Operational Limitations: Comply with "Conditions Applicable to Multiple	DCRC has proposed deletion of this condition.	DAQ concurs with respect to deleting the combined NOx emissions limit of 1,261 TPY from Boilers 1, 2 and 3 and the 2 CCUs because they will be subsumed in the facility-wide NOx cap. However, DAQ disagrees with respect to Boiler 2 for the reasons described in DAQ's response to existing Part 3 Condition a.2.i.E. above. Furthermore, DAQ disagrees with the proposed deletion of the operational limitation insofar as they apply to the requirements for Boiler 2.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
		Pollutants" in Condition 3 - Table 1.a.2.		
Facility-wide Emission Limit for Nitrogen Oxides (NO_x): The following emission units are subject to a facility-wide emission limit for NO_x ("NOx Cap") (collectively the "NOx Cap Units") in accordance with the conditions provided in this section: **Emission Unit No. 10** (Vapor Combustion Unit); **Emission Unit No. 15** (Marine Vapor Recovery (MVR) System); **Emission Unit No. 21** (Crude Unit Atmospheric Tower Heater 21-H-701, and Crude Unit Vacuum Tower Heater 21-H-2); **Emission Unit No. 22** (FCU, Wet Gas Scrubber (WGS), and Selective Non-Catalytic Reduction System (SNCR), FCU Start Up Heater 22-H-1, FCU Selas Steam Superheater 22-H-2, FCU Carbon Monoxide Boiler 22-H-3 and FCU Back Up Incinerator 22-H-4; **Emission Unit No. 23** (FCCU Reactor, Catalyst Regenerator, Start Up Heaters 23-H-1A and B, Carbon Monoxide Boiler 23-H-3 and Wet Gas Scrubber System); **Emission Unit**			Emission Standards: *[Reference: 7 **DE Admin. Code** 1112, Section 5 dated 11/24/93]* A. During the period between January 1, 2011 and December 31, 2013, the Owner/Operator shall not cause or allow the emission of NO_x in excess of 2,525 TPY from the NOx Cap Units, combined on a rolling twelve (12) month basis. B. During the twelve (12) month rolling period beginning on December 31, 2013 and ending on December 31, 2014, the Owner/Operator shall not cause or allow the emission of NO_x in excess of 2,225 TPY from the NOx Cap Units, combined on a rolling twelve (12) month basis. C. During the twelve (12) month rolling period beginning on December 31, 2014 and ending on December 31, 2015, and for each subsequent twelve (12) month rolling period, the Owner/Operator shall not cause or allow the emission of NO_x in excess of 1,650 TPY from the NOx Cap Units, combined on a rolling twelve (12) month basis. D. During the period of May 1 through September 30 of each calendar year (the "Ozone Season"), the Owner/Operator shall not cause or allow the emission of NO_x in excess of 1,500 TPY from the NOx Cap Units, combined. E. The plantwide applicability limit ("PAL") for the attainment pollutant, nitrogen dioxide ("NO_2") shall be 2,675 TPY.	DAQ disagrees with the citation of 7 **DE Admin. Code** 1112, Section 5 dated 11/24/93 as the applicable regulation for the incorporation of the NOx cap. The correct references should be 7 **DE Admin. Code** 1125 and 7 **DE Admin. Code** 1142. DAQ concurs with the proposed facility-wide NOx caps. However, it has rephrased the language to make it consistent with the DCRC Agreement and to read as follows: A. The initial NOx Cap for the Refinery shall be 2525 tons per year, evaluated over each 12 consecutive month rolling period, commencing with the twelve month rolling period comprised by CY2011. B. The NOx Cap will be further reduced to 2225 tons per year, evaluated over each 12 consecutive month rolling period, commencing with the 12 month rolling period beginning on December 31, 2013 and ending on December 31, 2014. C. The NOx Cap will be further reduced to 1650 tons per year, evaluated over each 12 consecutive month rolling period, commencing with the 12 month rolling period

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
No. 25 (Cracked Naphtha Hydrotreater (CNHT) Unit, Butamer Unit and Cooling Tower); **Emission Unit No. 28** (Sulfur Recovery Area (SRA): Claus Units I and II; Sulfur Pits and Shell Claus Offgas Treatment (SCOT) Units I and II); **Emission Unit No. 29** (Catalytic Hydrodesulfurizer Trains 29-1 through 29-5 and Process Heaters 29-H-101 and 29-H-2 through 29-H-9; **Emission Unit No. 32** (Process heater 32-H-101); **Emission Unit No. 33** (Selective Hydrogenation Unit and Process Heaters 33-H-1 and 33-H-2); **Emission Unit No. 34** (Olefins Plant and Process Heater 134-H-101); **Emission Unit No. 36** (Hydrocracker Unit, Process heaters 36-H-1, 36-H-2 and 36-H-3); **Emission Unit No. 37** (Steam Methane Reformer Hydrogen Plant, Heaters 37-H-1A/B); **Emission Unit No. 40** (Frozen Earth Storage System Flare); **Emission Unit No. 42** (Continuous Catalyst Regenerator (CCR) Reformer, Reformer Charge Heater 42-H-1,2,3 and Reboiler Heater 42-H-7);				beginning on December 31, 2014 and ending on December 31, 2015. D. During the period of May 1 through September 30 of each calendar year (the "Ozone Season"), the Owner/Operator shall not cause or allow the emission of NO_x in excess of 1,500 TPY from the NOx Cap Units, combined. F. DAQ disagrees with respect to the proposed PAL limit of 2,675 TPY insofar as it includes 39 TPY which is a significance threshold applicable for potential future changes above which PSD-NSR would be triggered. Furthermore, there is no provision in the DCRC Agreement to include an additional 39 TPY in the NO_2 PAL. Therefore, DAQ proposes to hold the PAL limit for NO_2 at the baseline level of 2636 TPY.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
Emission Unit No. 45 (Refinery utilities, North & South Flares and Gas Recovery System, Package Boilers); **Emission Unit No. 80** (Boiler #1, Boiler #2, Boiler #3 and Boiler #4; **Emission Unit No. 84** (Combined Cycle Unit #1 and Combined Cycle Unit #2)				
Facility-wide Emission Limit for Nitrogen Oxides (NO_x)			DCRC has proposed the following compliance method: Compliance Method *[Reference: 7 **DE Admin. Code** 1130 Section 6.3.1 dated 12/11/00]* A. The twelve (12) month rolling periods for purposes of determining compliance with the NO_x Emission Standard (A) shall consist of NO_x emissions measured in accordance with Compliance Method (E) between January 1, 2011 and December 31, 2013. B. The twelve (12) month rolling period for purposes of determining compliance with the NO_x Emission Standard (B) shall consist of NO_x emissions measured in accordance with Compliance Method (E) between December 31, 2013, and December 31, 2014. C. The twelve (12) month rolling periods for purposes of determining compliance with the NO_x Emission Standard (C) shall consist of NO_x emissions measured in accordance with Compliance Method (E) starting December 31, 2014. D. Compliance with Emission Standard (D) shall be determined based on NO_x emissions measured in accordance with Compliance Method (E) starting May 1, 2011.	DAQ finds DCRC's proposal to be ambiguous and inconsistent with the provisions in the DCRC Agreement. DCRC's proposed language leaves room for interpretations not provided for in the Agreement. For instance it provides DCRC with the option of implementing "*any of the following methods"* in DCRC proposal E. However, paragraph 22 of the DCRC Agreement clearly states that sources already equipped with CEMS shall continue to monitor NOx emissions with CEMS. Therefore, DAQ has reconstructed the compliance method as follows: A. Compliance with the Emission Standards shall be based on CEMS for the following units: • 21-H-1 • 21-H-701 • 22-H-3 • 23-H-3 • 37-H-1A/B • 42-H-1,2,3 • 80-1

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
			E. Unless otherwise specified in this permit, the Owner/Operator shall determine compliance with the Emission Standards (A), (B), (C), (D) and (E) by selecting and implementing any of the following methods: 1. Installation and operation of CEMS; 2. Determination and use of a NO_x emission factor based upon the results of the most recent performance testing conducted in accordance with a protocol approved by DNREC, or performed in accordance with applicable performance testing methods established and published by EPA and appropriate for measuring NO_x emissions from the relevant source; 3. Published NO_X emission factors for such source or category of sources; 4. Any other method proposed by the Owner/Operator and approved by the Department. F. For purposes of demonstrating compliance with Emission Standards (A), (B), (C), (D) and (E) the Owner/Operator shall account for NO_x emissions from permitted sources during all periods of startup, shutdown or malfunction of such equipment. To the extent that such emission rates are not measured by CEMS during such periods of startup, shutdown or malfunction, and to the further extent that performance testing for such source did not establish emission factors for such equipment reflective of operations during periods of startup, shutdown or malfunction, then the Owner/Operator shall estimate such emission rates from such source during any periods of startup,	• 80-2 • 80-3 • 80-4 • 84-1 • 84-2 B. Compliance with the Emission Standards shall be based on the fuel usage and the determination and use of a NO_x emission factor based upon the results of the most recent performance testing conducted in accordance with a protocol approved by DNREC, for the following units: • 25-H-401 • 25-H-402 • 32-H-101 C. For 25-H-401 and 25-H-402, oxygen parametric monitoring may be used as an alternative method. Hourly average NOx emissions shall be calculated consistent with the methodologies of the Premcor submittals to the Department dated November 19, 2007 and April 16, 2008 or by alternate methodologies approved by the Department.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
			shutdown or malfunction in accordance with best engineering judgment, provided however that the Owner/Operator must report to the Department the basis for the Owner/Operator's emission projections in such instance, and DNREC may object to the Owner/Operator's emission estimation methodology. G. Notwithstanding the requirements of Compliance Method (E), to the extent that any applicable federal regulatory standard governing the operation of a NO_x CEMS at a NOx Cap Unit requires data substitution methods relevant to compliance under such applicable regulatory standard, the Owner/Operator need not utilize such data substitution procedures to determine NO_x emission rates from a NOx Cap Unit during any period of CEMS outage or out-of-control periods for purposes of determining compliance with Emission Standard (A), (B), (C), (D) or (E), if the Owner/Operator can identify an alternative basis for estimating NO_x emissions from such source during such period of CEMS outage or out-of-control operation. H. To the extent that the Owner/Operator determines the NO_x emission rate for a NOx Cap Unit based upon the NO_x emission factor derived from the most recent performance test conducted in accordance Compliance Method (E)(2), the Owner/Operator may, at its election, conduct performance testing in addition to that required by applicable standards to establish a lower NO_x emission factor for such source to be used in demonstrating compliance with Emission	D. Fuel usage and published NO_X emission factors for such source or category of sources for all other affected units or any other method proposed by the Owner/Operator and approved by the Department. E. For purposes of demonstrating compliance with the NOx Caps the Owner/Operator shall account for NO_x emissions from permitted sources during all periods of startup, shutdown or malfunction of such equipment. To the extent that such emission rates are not measured by CEMS during such periods of startup, shutdown or malfunction, and to the further extent that performance testing for such source did not establish emission factors for such equipment reflective of operations during periods of startup, shutdown or malfunction, then the Owner/Operator shall estimate such emission rates from such source during any periods of startup, shutdown or

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
			Standard (A), (B), (C), (D) or (E), provided however that the Owner/Operator must secure advanced approval from the Department of any proposed adjusted NO_x emission factor. The Department shall approve or disapprove any request made by the Owner/Operator for an adjusted emission factor within 90 days of receiving information from the Owner/Operator sufficient to allow the Department to determine the acceptability of such adjusted emission factor.	malfunction in accordance with best engineering judgment, provided however that the Owner/Operator must report to the Department the basis for the Owner/Operator's emission projections in such instance, and DNREC may object to the Owner/Operator's emission estimation methodology. F. To the extent that any applicable federal regulatory standard governing the operation of a NO_x CEMS at the refinery requires data substitution methods relevant to compliance demonstrations under such applicable regulatory standard, the Owner/Operator need not utilize such data substitution procedures to determine NO_x emission rates from the relevant source at the Refinery during any period of CEMS outage or out-of-control periods for purposes of determining compliance with Emission Standards if the Owner/Operator can identify an alternative

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				basis for estimating NO_x emissions from such source during such period of CEMS outage or out-of-control operation. G. To the extent that any applicable regulatory standard requires the Owner/Operator to conduct performance testing for NOx emissions for a specific source at the Refinery, the Owner/operator shall determine the NO_x emission rate for such source based upon the NO_x emission factor derived from the most recent performance test conducted in accordance with the applicable regulatory standard, provided however that the Owner/Operator may, at its election, conduct performance testing in addition to that required by applicable standards to establish a lower NO_x emission factor for such source to be used in demonstrating compliance with the NOx Caps provided however that the Owner/Operator must secure advanced approval

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
				from the Department of any proposed adjusted NO_x emission factor. The Department shall approve or disapprove any request made by the Owner/Operator for an adjusted emission factor within 90 days of receiving information from the Owner/Operator sufficient to allow the Department to determine the acceptability of such adjusted emission factor.
Facility-wide Emission Limit for Nitrogen Oxides (NO_x)			DCRC has proposed the following monitoring/testing requirements. Monitoring/Testing: *[Reference: 7 **DE Admin Code** 1130 Sections 6.1.3.1 dated 12/11/00]* A. The Owner/Operator shall comply with the individual Monitoring/Testing requirements provided in this permit for each NOx Cap Unit.	DAQ concurs.
Facility-wide Emission Limit for Nitrogen Oxides (NO_x)			DCRC has proposed the following recordkeeping requirements. Recordkeeping: *[Reference: 7 **DE Admin Code** 1130 Section 6.1.3.2 dated 12/11/00]* A. The Owner/Operator shall maintain, for a period of five (5) years from the date of compliance demonstration for Emission Standard (A), (B), (C), (D) or (E) records necessary to demonstrate compliance with Emission Standard (A), (B), (C), (D) or (E). 1. To the extent that the Owner/Operator determines NO_x emissions by use of CEMS, then such records shall consist of the data generated by the DAHS associated with	DAQ disagrees. In order to make the recordkeeping requirements consistent with DAQ's revisions to DCRC's proposals, DAQ has made the following changes: A. All necessary records to assess compliance with the emission standards shall be maintained for a period of 5 years. B. CEMS records, as applicable shall comprise of CEMS data, calibration and audit results. C. Parametric monitoring

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
			the CEMS. 2. Where NO_x emissions are determined in accordance with emission factors derived from performance testing, the Owner/Operator shall maintain copies of all performance tests, as well as hours of operation and throughput rate for relevant sources, to the extent applicable to determining NO_x emissions for such sources. 3. To the extent that the Owner/Operator determines NO_x emissions for a NOx Cap Unit based upon published emission factors, then the Owner/Operator shall maintain copies of the information constituting the source of such emission factors, as well as records of the operating hours and/or throughput rate for such equipment, to the extent applicable to the determination of NO_x emission rates for such source. 4. The Owner/Operator shall maintain records of all periods of startup, shutdown and malfunction for each NOx Cap Unit, in addition to such other information concerning such startup, shutdown or malfunction event necessary to determine emissions from such source. B. The Owner/Operator shall comply with the individual Recordkeeping requirements provided in this permit for each NOx Cap Unit and shall maintain the rolling twelve (12) month NO_x emission data in accordance with Condition 3(b).	data or performance test data as applicable. D. Daily and monthly fuel usage and the applicable emission factor used in calculating monthly emissions. E. Records of monthly NOx emissions from each NOx emissions unit under the facility-wide NOx cap and the rolling twelve month NOx emissions from each NOx emissions unit under the facility-wide NOx cap. The NOx emissions from each NOx emissions unit under the facility-wide NOx cap shall be summed up and compared to the applicable NOx cap limit. F. Records of all periods of startup, shutdown and malfunction for each NOx Cap Unit, in addition to such other information concerning such startup, shutdown or malfunction event necessary to determine emissions from such source.
Facility-wide Emission			DCRC has proposed the following reporting	DAQ concurs.

NOx Cap Emissions Unit	Existing TV Permit Part and Condition Citation	Existing TV Permit Condition	DCRC's Proposal	DAQ Determination and Comments
Limit for Nitrogen Oxides (NO_x)			requirements: i. Reporting: In addition to the requirements of Conditions 2(a), 2(b)(9), 2(f)(3), 3(b)(1)(ii), and 3(c)(2) of this permit, the Company shall: *[Reference: 7 DE Admin Code 1130 Sections 6.1.3.2.3 and 6.2.1 dated 12/11/00]* A. On or before July 1, 2011, submit to the Department a report of the annual NO_x emissions for all NOx Cap Units for the twelve (12) month period ending with May 31, 2011. B. On or before January 31, 2012, and every six months thereafter, submit to the Department a report of the annual NO_x emissions for all NOx Cap Units for each rolling twelve (12) months period concluding during the prior semiannual period.	

As mentioned above (see page 10 of this memorandum) the second driver behind this proposed significant permit modification is to incorporate the applicable requirements applicable to the facility following the issuance of recently issued permits pursuant to **7 DE Admin Code 1102**[22]**.** The following permits have been issued to the facility pursuant to **7 DE Admin Code 1102:**

- **Permit: APC-81/0784-OPERATION (A2)** dated February 20, 2009 for the crude unit vacuum heater, 21-H-2.
- **Permit: APC-95/0570-OPERATION (A3)(NSPS)** dated February 20, 2009 for the crude unit atmospheric heater, 21-H-701
- **Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1)** dated May 26, 2009 for 4 package boilers
- **Permit: APC-90/0288-OPERATION (A9)** dated May 26, 2009 for Boiler 1
- **Permit: APC-90/0289-OPERATION (A7)** dated May 26, 2009 for Boiler 2
- **Permit: APC-90/0290-OPERATION (A8)** dated May 26, 2009 for Boiler 3
- **Permit: APC-90/0291-OPERATION (A2)** dated May 26, 2009 for Boiler 4
- **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)** dated May 26, 2009 for CCUs I & II
- **Permit: APC-97/0503-OPERATION (A7)(LAER)(NSPS)** dated July 23, 2009 for CCUs I & II

The following applications were submitted to modify the TV permit to incorporate the applicable requirements in the above referenced permits:

- Application dated February 22, 2010 for **Permit: APC-81/0784-OPERATION (A2)** and **Permit: APC-95/0570-OPERATION (A3)(NSPS)** both dated February 20, 2009.
- Application dated May 26, 2010 for **Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1)**, **Permit: APC-90/0288-OPERATION (A9)**, **Permit: APC-90/0289-OPERATION (A7)**, **Permit: APC-90/0290-OPERATION (A8)**, **Permit: APC-90/0291-OPERATION (A2)**, and **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)** all dated May 26, 2009.
- Application dated May 26, 2010 for **Permit: APC-97/0503-OPERATION (A7)(LAER)(NSPS)** dated July 23, 2009.

Table 10 below provides the details of the new applicable requirements from these permits that are being transferred to the modified TV permit.

[22] These applicable requirements are the result of permits issued to the facility after the issuance date of the most recent TV permit revision, i.e. A**dministrative Permit Modifications** to **Permit: AQM-003/00016 – Part 1 Renewal 1 Revision 4**, **Permit: AQM-003/00016 – Part 2 Revision 4**, and **Permit: AQM-003/00016 – Part 3 Renewal 1 Revision 4** all dated July 22, 2010.

Table 10: New Applicable Requirements

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
Permit: APC-81/0784-OPERATION (A2) and **Permit: APC-95/0570-OPERATION (A3)(NSPS)**[23]	2.1.1	Volatile Organic Compound (VOC) Emissions For 21-H-701 and 21-H-2 combined: 0.003 lb/mmBtu and 9.2 TPY.	Part 2, Condition 3, Table 1, c.6.i.
	2.1.2	Nitrogen Oxides (NOx) Emissions For 21-H-701 and 21-H-2 combined: 0.04 lb/mmBtu on a 3-hour rolling average, 20 lb/hour on a 24-hour rolling average, and 60.9 TPY.	Part 2, Condition 3, Table 1, c.4.i.
	2.1.3	Particulate Matter (PM_{10}) Emissions (inclusive of H_2SO_4): For 21-H-701 and 21-H-2 combined 0.02 lb/mmBtu and 60.9 TPY.	Part 2, Condition 3, Table 1, c.2.i.B.
	2.1.4	Sulfur Dioxide (SO_2) Emissions For 21-H-701 and 21-H-2 combined: 0.063 lb/mmBtu on a 3-hour rolling average and 80.4 TPY. The short term (lb/mmBtu) limit is an interim limit based on 318 ppm TRS in RFG and 843 Btu/dscf HHV of the RFG.	Part 2, Condition 3, Table 1, c.3.i.B.
	2.1.5	Carbon Monoxide (CO) Emissions For 21-H-701 and 21-H-2 combined: 0.03 lb/mmBtu and 91.4 TPY.	Part 2, Condition 3, Table 1, c.5.i.A.
	2.1.6	Sulfuric Acid (H_2SO_4) Emissions For 21-H-701 and 21-H-2 combined: 0.002 lb/mmBtu and 2.4 TPY. The short term (lb/mmBtu) limit is an interim limit based on 318 ppm TRS in RFG and 843 Btu/dscf HHV of the RFG.	Part 2, Condition 3, Table 1, c.8.i.A.
	2.17	Ammonia (NH_3) Emissions	Part 2, Condition 3, Table 1, c.9.i.A.

[23] The application dated February 22, 2010 also identified Conditions 3.1.1 and 3.1.2 as being applicable requirements that established heat input operational limitations on 21-H-701 and 21-H-2. However,

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
		For 21-H-701 and 21-H-2 combined: 10 ppmvd @ 3 % O_2 and 16.5 TPY.	
	3.1.1 and 3.1.2	3.1.1 The heat input to Unit 21-H-701 shall not exceed 456 mmBtu/hour on a 12-month rolling average basis and 504 mmBtu/hour on a 24-hour rolling average basis. 3.1.2 The heat input to Unit 21-H-2 shall not exceed 240 mmBtu/hour on a 12-month rolling average basis and 249 mmBtu/hour on a 24-hour rolling average basis.	DAQ has not transferred these conditions into the modified TV permit because DAQ concurs with DCRC 's proposal in the modified TV permit application that the heat input restrictions are no longer necessary since both emissions units have unit specific emission limits for all pollutants. See DAQ's response to Part 2, c.1.i.B. and c.1.i.C. on Page 16 of this memorandum.
Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1), **Permit: APC-90/0288-OPERATION (A9)**, **Permit: APC-90/0289-OPERATION (A7)**, **Permit: APC-90/0290-OPERATION (A8)**, **Permit: APC-90/0291-OPERATION (A2)**, and **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)**	2.1.1.2	NO_x emissions shall not exceed 0.04 lb/mmBtu each from Boiler Nos. 1 and 2 on a 24-hour rolling average, 0.2 lb/mmBtu from Boiler No. 3 on a 24-hour rolling average and 0.015 lb/mmBtu from each package boiler.	DAQ concurs with respect to Boiler 1 because it will now fall under the facility-wide NOx cap. See DAQ's response DCRC's new proposal to comply with "Facility-wide Emission Limit for Nitrogen Oxides (NOx)" in Condition 3, Table 1.j. However, DAQ disagrees with respect to the limitation for Boiler 2 for the reasons described in DAQ's response to existing Part 3 Condition a.2.i.E. in Table 9 of this memorandum because deletion of this condition will contravene Criterion c of Paragraph 12 of the DCRC Agreement. See DAQ's response to Part 3, a.5.i.B in Table 9.
	3.5	Boiler No. 1 shall not be operated until it is upgraded to meet the standard in this permit after issuance of a permit for the upgrades.	DAQ has not transferred this condition because it concurs once boiler1 comes under the NOx cap, its upgrade will no longer be required.

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
	4.4	Compliance with Conditions 2.1.4, 2.1.5 and 2.1.6 shall be demonstrated by firing only natural gas or by using annual stack test based emissions factors obtained while firing RFG and RFG fuel flow rates for the boilers.	Part 3, Condition 3, Table 1, a.7.iii.
Permit: APC-97/0503-OPERATION (A7)(LAER)(NSPS)	3.3	When syngas is not fired in the combustion chambers of the CCUs, only ultra low sulfur diesel fuel (ULSD) may be fired in its place. The combined utilization of ULSD for both CCUs may not exceed 13,300,000 gallons in any 12 consecutive months.	Part 3, Condition 3, Table 1, d.1.ii.A.
Permit: APC-97/0503-OPERATION (A7)(LAER)(NSPS)[24]	3.4	The sulfur content in the LSDF oil shall not exceed 0.0015 weight percent (15 ppmw).	Part 3, Condition 3, Table 1, d.1.ii.B.
Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1), **Permit: APC-90/0288-OPERATION (A9)**, **Permit: APC-90/0289-OPERATION (A7)**, **Permit: APC-90/0290-OPERATION (A8)**, **Permit: APC-90/0291-OPERATION (A2)**, and **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)**	2.1.2 through 2.1.9	The words "and the package boilers" have been appended to each emission limitation. Thus, each introductory sentence in the emission limitations for the pollutants enumerated in Conditions 2.1.2 through 2.1.9 reads as follows: "….. emissions from the CCUs, Boilers 1, 2, 3 and the 4 package boilers combined	Part 3, Condition 3, Table 1, f.1 through f.7
	2.1.1.1	The combined NO_x emissions from the CCUs, Boiler Nos. 1, 2, 3 and the 4 package boilers shall not exceed 1,260.8 TPY. NO_x emissions shall not exceed the following unit specific limits: 125.4 TPY for Boiler 2, 541.4 TPY for Boiler No. 3 and 19.3 TPY from the 4 package boilers	DAQ has not transferred this condition because it has been subsumed by the facility wide NOx cap. However, the unit specific limit for Boiler 2 remains in force for the reasons described in DAQ's response to existing Part 3 Condition a.2.i.E. in Table 9 of this memorandum.
	2.1.1.3	The combined NO_x emissions from Boiler Nos. 1, 2, 3, 4 and the 4 package boilers shall not exceed 715 TPY.	DAQ has not transferred this condition because it has been subsumed by the facility wide NOx cap.

[24] All references to LSDF have been replaced with ULSD in the modified TV permit to make it consistent with the changes effectuated by condition 3.4.

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
	3.6	The package boilers shall be operated preferentially over Boilers 3 and 4 to the extent practicable in order to comply with the emission limitation in Condition 2.1.1.3.	Part 3, Condition 3, Table 1, f.4.ii.A.
	4.9.7	Annual stack testing conducted pursuant to Conditions 4.9.1, 4.9.2, 4.94, and 4.9.5 shall not be required for the package boilers provided the package boilers only fire natural gas. Stack testing must be conducted according to Conditions 4.9.1 through 4.9.5 within 180 day of the date in which the company first fires refinery fuel gas in any package boiler.	Part 3, Condition 3, Table 1, f.7.iv.
Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1), **Permit: APC-90/0288-OPERATION (A9)**, **Permit: APC-90/0289-OPERATION (A7)**, **Permit: APC-90/0290-OPERATION (A8)**, **Permit: APC-90/0291-OPERATION (A2)**, and **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)**	3.3	The heat input to each package boiler shall not exceed 99.99 mmBtu/hour on a 24-hour rolling average basis.	Part 3, Condition 3, Table 1, g.1.i.A.
	3.1	Only desulfurized refinery fuel gas (RFG) with a hydrogen sulfide content less than 0.1 grain/dscf on a 3 hour rolling average and/or natural gas may be fired in the 4 package boilers.	Part 3, Condition 3, Table 1, g.1.i.B.
	3.4	No package boiler shall be operated unless its SCR is operating properly except for durations not to exceed 6 hours during planned start up or shut down. Proper operation of the SCR system shall be based on adherence to the manufacturer's recommended operating practices.	Part 3, Condition 3, Table 1, g.1.i.C.
	4.10 and 4.11	Compliance with Condition 3.1 shall be based on instruments installed for continuously monitoring and recording the concentration (dry basis) of H_2S and TRS in syngas before it is combusted in any fuel burning device. The instruments shall be located downstream of all process steps which impact the composition of syngas prior to its being combusted in any fuel burning device. These instruments shall conform to the QA/QC requirements of Appendix "F" in 40 CFR 60. The H_2S monitor shall conform to Performance Specification 7 of 40 CFR 60, Appendix "B". Method 11 of 40 CFR 60, Appendix "A" shall be used for conducting the relative accuracy evaluations. The TRS monitor shall conform to Performance Specification 5 of 40 CFR 60, Appendix "B". Method 15 of 40 CFR 60, Appendix "A" shall be used for conducting relative accuracy evaluations. Compliance with Conditions 3.2, 3.3, and 3.4 shall be based on the record keeping requirements.	Part 3, Condition 3, Table 1, g.1.ii and iii.

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
	5 and 6	Recordkeeping and reporting requirements	Part 3, Condition 3, Table 1, g.1.iv and v.
	2.1.4 and 2.1.5	A. PM_{10} emissions from the 4 package boilers combined shall not exceed 18.2 TPY. B. PM_{10} emissions including H_2SO_4 shall not exceed 0.0104 lb/mmBtu from each package boiler. C. TSP emissions from the 4 package boilers 9.5 TPY. D. TSP emissions shall not exceed 0.0054 lb/mmBtu from each package boiler.	Part 3, Condition 3, Table 1, g.2.i.
Permit: APC-2009/0089-CONSTRUCTION/OPERATION (A1), **Permit: APC-90/0288-OPERATION (A9)**, **Permit: APC-90/0289-OPERATION (A7)**, **Permit: APC-90/0290-OPERATION (A8)**, **Permit: APC-90/0291-OPERATION (A2)**, and **Permit: APC-97/0503-OPERATION (A6)(LAER)(NSPS)**	2.1.2	SO_2 emissions from the 4 package boilers 39.4 TPY.	Part 3, Condition 3, Table 1, g.3.i.
	2.1.1	NO_x emissions from the 4 package boilers 19.3 TPY. NO_x emissions shall not exceed 0.015 lb/mmBtu from each package boiler.	Part 3, Condition 3, Table 1, g.4.i.
	2.1.3	CO emissions from the 4 package boilers 59.63 TPY. CO emissions shall not exceed 0.034 lb/mmBtu from each package boiler.	Part 3, Condition 3, Table 1, g.5.i.
	2.1.6	VOC emissions from the 4 package boilers 2.5 TPY. VOC emissions shall not exceed 0.0014 lb/mmBtu from each package boiler.	Part 3, Condition 3, Table 1, g.6.i.
	2.1.7	H_2S0_4 emissions from the 4 package boilers 6.4 TPY.	Part 3, Condition 3, Table 1, g.7.i.
	2.1.9	NH_3 emissions shall not exceed 10 ppmvd @ 3 % O_2 and 11.9 TPY for the 4 package boilers.	Part 3, Condition 3, Table 1, g.8.i.

7 DE Admin. Code 1102 Permit No.	Condition No.	Condition Description	Transferred to
	4.7	Compliance with Condition 2.1.9 shall be based on monitoring the stack gas by obtaining weekly grab samples from a location downstream of the SCR using a Department approved method. The Company may request the Department for approval of less frequent monitoring if 24 consecutive sampling events indicate the ammonia slip to be less than 5 ppmvd @ 3 % O_2.	Part 3, Condition 3, Table 1, g.8.iii. and iv.
	2.2	None of the package boilers shall emit visible air contaminants exceeding 20% opacity for an aggregate of more than 3 minutes in any 1 hour period, or more than 15 minutes in any 24 hour period.	Part 3, Condition 3, Table 1, g.9.i. and iv.
	4.8.2 through 4.8.5	If visible emissions are observed, the Company shall take corrective actions and/or conduct a visible observation in accordance with Paragraph 4.8.5 below. If no visible emissions are observed, no further action is required. If required under Condition 4.8.3 above, the Company shall, in accordance with Subsection 1.5(c) of Regulation No. 20, conduct visual observations at fifteen-second intervals for a period of not less than one hour except that the observations may be discontinued whenever a violation of the standard is recorded. The additional procedures, qualification and testing to be used for visually determining the opacity shall be those specified in Section 2 & 3 (except for Section 2.5 and the second sentence of Section 2.4) of Reference Method 9 set forth in Appendix A, 40 CFR, Part 60, revised July 1, 1982.	

Additionally, as part of this modified TV permit application DCRC has submitted a proposed marked up version of the draft permit including numerous changes. Table 11 provides DAQ's evaluation of these other changes.

Table 11: Evaluation of Other Changes

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
Part 1 Changes			
Condition 3, Table 1.a.1.iii.A, bc.1.iii.A, c.1.iii.A, d.1.iii.A, e.1.iii.A	Compliance with the emission standard is based on compliance with the NSPS limit of 0.1 grain/dscf limit of H_2S in RFG.	To base compliance on fuel quality instead of the NSPS limit for h2s in RFG. These conditions provide that for certain emission units the compliance method for the PM emission standard of 0.3 lb/MMBtu is met by achieving compliance with the NSPS limit of 0.1 gr/dscf for H2S in refinery fuel gas. The PM standard, however, can be met even if the H2S limit is exceeded. In this instance, a compliance method that is based on "fuel type and quality" is more appropriate.	DAQ concurs.
Condition 3, Table 1.a.2, bc.2, fi.2	Sulfur Dioxide (SO_2)	Various provisions within these sections of the Permit reference monitoring, reporting and recordkeeping requirements provided by the Alternate Monitoring Plan established under Subpart J of the New Source Performance Standards. On June 24, 2008, Subpart J was amended to exempt certain fuel gas streams, including the fuel gas stream associated with these units, from continuous monitoring requirements, thereby obviating the need for an Alternate Monitoring Plan for these units. Premcor included this information in the permit application dated February 27, 2009 along with a request to exempt these and other fuel gas streams from Subpart J monitoring and to remove any references to the need to develop and follow an Alternate Monitoring Plan.	DAQ concurs.
Condition 3, Table 1.a.3.i.B	For Units 29-H-101 and Units 29-H-2 through 29-H-9: NO_X emissions shall not exceed those achieved through an	Removal of tune-up requirement for 29-H-101 because compliance with the NO_x emission standard is demonstrated by the installation of low NO_x burner technology per DE Regulation	DAQ disagrees. DCRC has not provided adequate justification to delete what is an existing requirement thereby contravening the provisions of Paragraph 15 of the DCRC Agreement.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
	annual tune up performed by qualified personnel. *[Reference: 7 DE Admin. Code 1112, Section 3.3.2 dated 11/24/93]*	1112 Section 3.3.1.	Furthermore, this requirement does not impede DCRC's ability to comply with the facility-wide NOx cap. On the contrary, a tuned up unit will be more likely to minimize its NOx contribution thereby facilitating compliance with the facility-wide cap and will operate in conformity with good air pollution control practices.
Condition 3, Table 1.ba.1.vi.D	Results of stack test required to demonstrate compliance with Operational Limitation B in accordance with Condition 3(b)(1)(v).	Removal of the stack testing requirement. The stack test for 32-H-101 has already occurred, and the report was submitted to DNREC. In addition, Condition 3(b)(1)(v) of the Permit separately requires DCRC to submit all stack tests to DNREC.	DAQ concurs.
Condition 3, Table 1.bb.1.v.A, 2.iv.A, 3.iv.A, 4.iv.A, 5.iv.A, 6.iv.A, 7.iv.A, 8.iv.A, 9.iv, 10.iv.A, 11.iv.A	All records and information required by this section shall be maintained in a manner that can be readily accessed at the plant site. *[Reference: 7 **DE Admin Code** 1130 Section 6.1.3.1.2 and 6.2.1 dated 12/11/00]*	Deletion. Similar condition listed in Condition 2(i)(2)	DAQ concurs.
Condition 3, Table 1.bc.3.iv.A	Recordkeeping: … A. All stack test data and results.	Deletion. The requirement to maintain stack test results is included in Condition 3(b).	DAQ concurs.
Condition 3, Table 1.fa.1.ii.E	Any storage vessel that has continuously been out of service since before August 18, 1998, shall not be returned to HAP service until it satisfies the applicable MACT requirements in 40 CFR Part 63, Subpart CC. *[Reference: 40 CFR Part 63, Subpart CC, Section 63.640 (h)(4) dated 6/12/1996]*	Deletion. All of the tanks listed in Section fa are already subject to Subpart CC, and thus this condition appears to apply to tanks that are not currently listed in the Permit. In other words, if DCRC wishes to operate any tank that has been out of service since before August 19, 1998, it will need to obtain a new permit from DNREC, at which time the Subpart CC standards will be included in the operating permit.	DAQ concurs.
Condition 3, Table 1.fa.1.v and vi	Recordkeeping and reporting requirements for tanks subject to 40 CFR Part 60, Subpart Kb ("Kb Tanks")	Deletion. 40 CFR §63.640(n)(8) states that Kb Tanks shall comply with the requirements of Subpart Kb in lieu of the requirements of Subpart CC, except in certain instances. The	DAQ concurs.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		conditions at issue in this section of the Permit, however, include references to the recordkeeping requirements of 40 CFR Part 63.	
Condition 3, Table 1.fe.1.vi.B	Quarterly reports of the rolling twelve month VOC emissions from Tank 471-TF-28.	Deletion. This obligation to submit quarterly VOC emission reports, regardless as to whether those emissions indicate exceedances of the VOC emission standard for Tank 471-TF-28, is redundant of, and potentially inconsistent with, DCRC's independent obligation to submit semi-annual deviation reports under the Title V program. Requiring submittal of two sets of similar emissions and related data, one semi-annual and the other quarterly, is unnecessary. Second, the requirement to submit VOC emissions data on a quarterly basis is inconsistent with parallel VOC reporting requirements for the tanks listed in Condition 3, Table 1.fc and fd. Third, the information required to be reported under this condition does not relate to "excess emissions," but rather emissions data, regardless as to whether the data reflects some emission standard exceedance.	DAQ disagrees with DCRC's rationale that it is redundant or inconsistent with DCRC's reporting obligations. However, DAQ is agreeing to remove this reporting requirement based on historic emissions data for Tank 471 which shows very low emissions. Therefore, DAQ finds it acceptable to roll this requirement into the existing semi-annual TV reporting schedule.
Condition 3, Table 1.fg.1	**Odor Control.**	To make state enforceable only	DAQ concurs.
Condition 3, Table 1.fg.1.v.A	Submit deviations in the Semi-Annual title V Report identified in the inspection(s) of Tank 470-TF-50 and the results of the inspection(s). A list of all corrective actions shall be included. The reports shall include proposed actions for problems that have not been resolved and provide a timetable for the Department's approval for corrections to be made. *[Reference: **APC-81/0120**]*.	Deletion. Other general conditions in the Permit, however, separately require DCRC to submit semi-annual deviation reports for deviation from any operational limitations, including the odor operational limitations listed in this section.	DAQ concurs because periodic compliance inspection requirements remain and the facility is nonetheless required to immediately report releases.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
Condition 3, Table 1.fi	Frozen Earth Storage System Flare	This section of the Permit provides conditions governing operation of the Frozen Earth Storage System Flare. These conditions provide specific authorization for DCRC to operate the flare under certain circumstances and do not provide emission limits for a number of air pollutants during such operations. Nevertheless, based upon recent enforcement actions pursued by DNREC, DNREC has taken the position that the emission of any air pollutant from the flare constitutes a violation of the Permit. In other words, DNREC has asserted that while it has authorized DCRC to operate the flare under circumstances, it has not authorized DCRC to emit pollutants from the flare during flare operation. Because operation of any flare, including, this one, necessarily involves the release of air pollutants, DCRC is requesting that this section be revised to clarify that the emission of air pollutants from the flare are authorized.	DAQ finds this issue to be moot because the FES has been emptied, is no longer operational, and is in the process of being decommissioned. Therefore, DAQ is deleting the requirements for this decommissioned emission unit.
Condition 3, Table 1.fi.1.ii (Proposed Condition 3, Table 1.fi.2.ii)	Compliance with the emission standard shall be based on the proper operation of the refrigeration vapor recovery system.	Revision of language to be consistent with similar language for other sources.	DAQ disagrees. Proper operation of the refrigeration vapor recovery system is essential to ensuring compliance.
Condition 3,Table 1.fi.1.iv.B (Proposed Condition 3, Table 1.fi.2.iv.B)	Recordkeeping: …Records of maintenance performed on the unit.	Removal of recordkeeping requirement to be consistent with similar requirements for other sources.	DAQ concurs.
Condition 3, Table 1.fj.1.vi	Reporting Requirements for Ethanol Blending Project	Deletion. This condition requires semi-annual reporting of results of VOC emissions and LDAR monitoring efforts that are in excess of the quantities specified in the emissions limitation. The Permit, however, separately and more generally requires DCRC to submit semi-annual deviation reports that list instances where emission limitations have been exceeded.	DAQ concurs.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
Part 2 Changes			
Condition 1.a	Secondary and tertiary treatment equipment (downstream of DNF), 1st and 2nd stage activated sludge, sand filtration and assorted sumps and equipment (listed as having "No emission points")	Replace "No emission points" with "Various'. Clarifies that there are emissions from these sources	DAQ concurs.
Condition 3, Table 1.ac.1.i	Emission Standard: The Owner/Operator shall not cause or allow the emission of particulate matter in excess of 0.3 lb/mm BTU heat input, maximum 2-hour average.	Emission Standard: Adds the language "from the VCU" at the end of the sentence. The Owner/Operator shall not cause or allow the emission of particulate matter in excess of 0.3 lb/mm BTU heat input, maximum 2-hour average from the VCU.	DAQ concurs.
Condition 3, Table 1.ac.1.ii.A	Compliance with the Emission Standard shall be based on the fuel usage and quality.	Deletes the word "usage" from the condition. Revision of the permit language to make it consistent with similar requirements in the Permit.	DAQ concurs.
Condition 3, Table 1.ac.1.iv	The following records shall be maintained in accordance with Condition 3(b): the type and rolling twelve month fuel usage by the VCU.	Deletes the words 'rolling 12-month' from the condition. This condition requires DCRC to maintain records of the rolling twelve month fuel usage of the vapor combustion unit. The corresponding emission standard for PM, however, is not tied to a rolling twelve month average, making the vapor combustion unit's rolling twelve month fuel usage irrelevant.	DAQ concurs.
Condition 3, Table 1.ac.4.ii.C	The VCU shall be operating properly whenever any of the following equipment is in operation except during periods of maintenance on the VCU or during emergency situations that require the shutdown of the VCU: • Crude Recovery Tank (372-TC-M) • Sludge Holding Tank (349-TM-M)	Per 40 CFR 63.348(b)(2), operating the Dissolved Nitrogen Floatation (DNF) unit and associated storage tanks without the VCU as an exempt (i.e., uncontrolled) waste management unit is allowed under the Benzene Waste Operations NESHAP (BWON) regulations as long as certain requirements regarding the benzene concentration and total annual benzene quantity of aggregated wastewater managed in the DNF are demonstrated. The VCU shall be operating properly whenever any of the following	DAQ disagrees. Firstly, DAQ believes DCRC's citation of the reference to the applicable regulation is incorrect and that the correct citation should be 40 CFR 61.348 (b)(2). Second, 40 CFR 61.348 (b)(2) states that the provisions of paragraph (b)(1) of this section do not apply to any waste management unit that the owner or operator demonstrates to meet the following conditions initially and, thereafter, at least once per year: (i) The benzene content of each waste stream entering the waste management unit is less than

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
	• DNF Tank 326 • DNF Tank 305 • DNF Tank 306 • Slop Oil Tank 10-D-109 • Slop Oil Tank 10-D-202 • Day Tank 356-TC-3 • Day Tank 357-TC-3 • Day Tank 358-TC-3	equipment is in operation except during periods of maintenance on the VCU that require the shutdown of the VCU, during emergency situations that require the shutdown of the VCU or during periods when the VCU is shutdown as allowed per 40 CFR 63.348(b)(2): • Crude Recovery Tank (372-TC-M) • Sludge Holding Tank (349-TM-M) • DNF Tank 326 • DNF Tank 305 • DNF Tank 306 • Slop Oil Tank 10-D-109 • Slop Oil Tank 10-D-202 • Day Tank 356-TC-3 • Day Tank 357-TC-3 • Day Tank 358-TC-3	10 ppmw on a flow-weighted annual average basis as determined by the procedures specified in 61.355 © of this subpart; and (ii) the total annual benzene quantity contained in all waste streams managed or treated in exempt waste management units comprising the facility wastewater treatment systems is less than 1 Mg/yr. Based on the past operating history of the WWTP, DAQ is convinced both the above conditions will be impractical to achieve after the refinery restarts and consequently inapplicable. Furthermore, DAQ had agreed to allow DCRC to shut down the VCU during the period when the entire refinery was shut down based on DCRC's representation that benzene containing wastes were over an order of magnitude lower than the 2 Mg exemption afforded by 40 CFR 61.342.
Condition 3, Table 1.ad	Emission Unit No. 10: Gasoline Dispensing Facility	The conditions listed in this section of the Permit are the applicable requirements for the Stage I and Stage II Vapor Recovery System per Regulation 1124 Sections 29 and 36. Gasoline dispensing facilities with a monthly throughput of less than 10,000 gallons are exempt from the monitoring, testing and recordkeeping requirements of Regulation 1124 Sections 29 and 36. The gasoline dispensing facility located at the Refinery has not had a monthly throughput of greater than 10,000 gallons under Premcor's ownership, and DCRC does not expect to exceed a monthly throughput of 10,000 gallons at any point in the future. Therefore, DCRC proposes that the only applicable requirement associated with the gasoline dispensing facility should be the requirement to maintain records showing the monthly throughput based on gasoline deliveries to the storage tank to demonstrate that the monthly throughput did not exceed 10,000 gallons of gasoline.	DAQ disagrees. The stage I and stage II vapor recovery requirements become applicable requirements once triggered by exceeding the 10,000 gallon monthly throughput. There is no mechanism in the regulations to allow this exemption if the monthly throughput has ever exceeded 10,000 gallons.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
Condition 3, Table 1.c.2.i.A	For 21-H-2: The Owner/Operator shall not cause or allow the emission of particulate matter in excess of 0.3 lb/mmBtu heat input, maximum 2-hour average.	Deletion. Removal of PM emission standard for 21-H-2 because the proposed emission standard for Condition 3, Table 1.c.2.i.B is more stringent	DAQ disagrees. This is a regulatory applicable requirement.
Condition 3, Table 1.c.2.iv.B	Monitoring/Testing: … B. The Owner/Operator shall continuously monitor the H2S content in the RFG.	This condition of the Permit provides that DCRC must continuously monitor the H2S content in the refinery fuel gas (RFG) combusted by heaters 21-H-2 and 21-H-701 for purposes of monitoring compliance with the PM limits for those heaters. The compliance methods, however, are based upon fuel type and quality for 21-H-2 and a stack-test based emission factor applied to a rolling twelve month fuel usage for 21-H-701. The continuous monitoring of H2S in RFG is not necessary to meet those compliance methods.	DAQ concurs.
Condition 3, Table 1.c.3.ii.A	Compliance with Emission Standard A shall be based on the H_2S CEMS for the RFG and on the monitoring requirements required by the AMP.	Deletion of the requirement of the AMP. On June 24, 2008, Subpart J was amended to exempt certain fuel gas streams, including the fuel gas stream associated with the Crude Unit, from continuous monitoring requirements, thereby obviating the need for Alternate Monitoring Plans for the Crude Unit. Premcor included this information in the permit application dated February 27, 2009 along with a request to exempt these and other fuel gas streams from Subpart J monitoring and to remove any references to the need to develop and follow an Alternate Monitoring Plan.	DAQ concurs.
Condition 3, Table 1.c.3.ii.B	Compliance with Emission Standard B shall be based on the rolling twelve month fuel usage and the rolling twelve month average sulfur content of the fuel as determined using H_2S CMS.	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009.Compliance with Emission Standard B shall be based on the rolling	DAQ concurs.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		twelve month fuel usage and the rolling twelve month average sulfur content of the refinery fuel gas as measured by a TRS analyzer.	
Condition 3, Table 1.c.3.iii.D	None	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009. The TRS monitor shall conform to the QA/QC requirements recommended by the manufacturer's specifications and listed in the QA/QC Plan for the TRS monitor. The TRS monitor shall conform to Performance Specification 5 of 40 CFR Part 60, Appendix "B." Relative accuracy evaluations shall be conducted using Method 15 of 40 CFR Part 60, Appendix "A".	DAQ concurs.
Condition 3, Table 1.c.3.iv.B	None	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009.	DAQ concurs.
Condition 3, Table 1.c.5.i.A	CO emissions from 21-H-701 shall not exceed 0.035 lb/mmBtu and 75.1 tons in any rolling 12 month period.	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009.CO emissions from 21-H-701 and 21-H-2 shall not exceed 0.03 lb/mmBtu and 91.4 tons in any rolling 12 month period.	DAQ concurs.
Condition 3, Table 1.c.5.iii.B	The Owner/Operator shall conduct stack tests at 5 year intervals to determine the emission factor in terms of lb/mmBtu.	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009. The Owner/Operator shall	DAQ concurs.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		conduct stack tests at 5 year intervals to determine the emission factor in terms of lb/mmBtu in accordance with Reference Method 10 in Appendix "A" of 40 CFR Part 60.	
Condition 3, Table 1.c.6.i.A	VOC emissions from 21-H-701 shall not exceed 0.003 lb/mmBtu and 6.4 tons in any rolling twelve month period.	VOC emissions from 21-H-701 and 21-H-2 combined shall not exceed 0.003 lb/mmBtu and 9.2 tons in any rolling twelve month period.	DAQ concurs.
Condition 3, Table 1.c.6.iii.B	The Owner/Operator shall conduct a stack test every 5 years to determine the emission factor in terms of lb/mmBtu.	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009. The Owner/Operator shall conduct a stack test every 5 years to determine the emission factor in terms of lb/mmBtu in accordance with Reference Method 25A in Appendix "A" of 40 CFR Part 60 and shall determine and report results as total hydrocarbons or shall conduct such other testing methodology and/or report results as approved by the Department.	DAQ concurs.
Condition 3, Table 1.c.7.iv.A	Observation records shall be maintained and made available to the Department upon request.	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009. A record of daily qualitative emission observations and Method 9 evaluations when emissions were observed.	DAQ concurs.
Condition 3, Table 1.c.8	None	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION (Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009. Conditions applicable to Sulfuric Acid (H_2SO_4)	DAQ concurs.
Condition 3, Table 1.c.9	None	Incorporation of the applicable requirements from Permits APC-95/0570-OPERATION	DAQ concurs.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		(Amendment 3)(NSPS) and APC-81/0784-OPERATION (Amendment 2) issued for the operation of 21-H-701 and 21-H-2 on February 20, 2009.Conditions applicable to Ammonia (NH_3)	
Condition 3, Table 1.e.1.i & iv	General Conditions for the FCCU	These conditions include operational limitations and recordkeeping requirements for a specific piece of pollution control equipment (i.e., the WGS+ system). The NOx control system for the FCCU, however, has not been finalized and installed, and it is possible that another control method will be used. Therefore, DCRC is requesting that the references to the NOx control system be removed from the Permit.	DAQ concurs.
Condition 3, Table 1.j.3.vi.B	During planned start-up and shutdown periods of incineration, ambient air monitoring data for the affected period shall be submitted to the Department daily. At the Department's request, copies of available air monitoring data shall be furnished to the Air Quality Management Division.	DCRC is requesting that this condition be removed from the Permit because previous monitoring during these periods indicates that there have been no potential exceedances of the NAAQS. Therefore, because it has been demonstrated that the ambient air quality has not exceeded NAAQS during planned start-up and shutdown periods, DCRC feels that it is not necessary to continue with this monitoring practice during these times. Previous monitoring reports are included in Attachment 5.	DAQ disagrees. This condition was specifically designed to address the impacts to ambient air quality during process upsets and malfunctions when there is the likelihood of experiencing releases of very large quantities of air pollutants. Deleting it will contravene good air pollution control practices.
Condition 3, Table 1.n.1	Flares	This section of the Permit provides conditions governing operation of the North and South flares. These conditions provide specific authorization for DCRC to operate the flares under certain circumstances and do not provide emission limits for a number of air pollutants during such operations. Nevertheless, based upon recent enforcement actions pursued by DNREC, DNREC has taken the position that the emission of any air pollutant from the flares constitutes a violation	DAQ disagrees with the proposed emission standard A. See DAQ's response to Condition 3, table 1.n.1 in Table 9 of this memorandum.

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		of the Permit. In other words, DNREC has asserted that while it has authorized DCRC to operate the flares under circumstances, it has not authorized DCRC to emit pollutants from the flare during flare operation. Because operation of any flare, including, these two, necessarily involves the release of air pollutants, DCRC is requesting that this section be revised to clarify that the emission of air pollutants from the flares are authorized.	
Condition 3, Table 1.n.2	Spent Caustic Stripper:	These conditions govern operation of the spent caustic stripper, which is designed to reduce the potential for odors emanating from caustic streams produced by several processes in the refinery. Because these conditions are odor based, they should be designated as "state-only" enforceable conditions. Indeed, Condition 3, Table 1.ob.2.i, which provides facility-wide odor conditions, explicitly recognizes that these odor conditions are state enforceable only.	DAQ concurs.
Part 3 Changes			
Condition 3, Table 1.a.2.i.A	No liquid fuels shall be burned in any of the boilers. Only desulfurized refinery fuel gas (RFG) or natural gas may be fired in Boilers 80-1, 80-2 and 80-4. Only desulfurized RFG, natural gas or syngas may be fired in Boiler 80-3.	These conditions are not applicable requirements currently imposed by the applicable state operating permit. That permit does prescribe what fuels can be burned in the boilers, but it does not call for any separate actions concerning a prohibition against liquid fuels. Because DNREC has attempted to impose these conditions concerning liquid fuel for the first time through the Permit, these conditions are not required nor supported by applicable law. Moreover, the conditions concerning the prohibition against burning liquid fuel require DCRC to demonstrate a negative annually, and it is unclear what records, if any, will be sufficient to demonstrate that no liquid fuels have been	DAQ disagrees with DCRC's rationale. DAQ had incorporated this condition because the former owners of the refinery had deliberately introduced and burned liquid condensate fuel in Boilers 1 and 3. A Notice of Violation issued to the facility was settled with the former owner after DAQ verified that the liquid condensate lines had been dismantled. Therefore, DAQ is willing to delete this condition.
Condition 3, Table 1.a.2.ii.A	Compliance with Operational Limitation (A) shall be based on Premcor demonstrating that only the allowable fuels and no other fuels have been combusted in the boilers during the compliance period and on the Monitoring/Testing requirements.		

Permit Condition	Current TV Language	Change Sought and Rationale	DAQ Comments
		burned in the boilers.	
Condition 3, Table 1.a.7.iii	Compliance with the VOC Emission Standards shall be demonstrated using stack test based emissions factors and fuel flow rates for the boilers.	Incorporation of the applicable requirements from Permit APC-2009/0089-C/O(A1) issued for the operation of the package boilers on May 26, 2009. Compliance with the VOC Emission Standards shall be demonstrated by firing only natural gas or by using annual stack test based emissions factors obtained while firing refinery fuel gas and refinery fuel gas flow rates for the boilers.	DAQ concurs.
Condition 3, Table 1.d	Emission Unit 84: Combined Cycle Units 84-1 and 84-2 (Emission Points 84-1 and 84-2)	Incorporation of the applicable requirements from Permit APC-97/0503-O(A7)(LAER)(NSPS) issued for the operation of the CCUs on July 23, 2009.	DAQ concurs.
Condition 3, Table 1.f	Combined Limits	Incorporation of the applicable requirements from Permit APC-2009/0089-C/O(A1) issued for the operation of the package boilers on May 26, 2009.	DAQ concurs.
Condition 3, Table 1.g	None	Incorporation of the applicable requirements from Permit APC-2009/0089-C/O(A1) issued for the operation of the package boilers on May 26, 2009.	DAQ concurs.

IV. Operational Flexibility

a. In addition to the operational flexibility specifically provided in the terms and conditions detailed in Condition 3 – Table 1 of this permit, the Owner and/or Operator is authorized to make any changes within the facility which contravenes the terms and conditions of this permit without a permit revision if the change:

   1. Is not a modification or otherwise prohibited under any provision of Title I of the Act or the State Implementation Plan (SIP); and *[Reference: 7 **DE Admin. Code** 1130 Section 6.8 dated 12/11/00]*

   2. Does not involve a change in any compliance schedule date; and *[Reference: 7 **DE Admin. Code** 1130 Section 6.8 dated 12/11/00]*

   3. Does not result in a level of emissions exceeding the emissions allowable under this permit, whether expressed herein as a rate of emissions or in terms of total emissions. *[Reference: 7 **DE Admin. Code** 1130 Section 6.8 dated 12/11/00]*

b. Before making a change under the provisions of Condition 4(a) of this permit, the Owner and/or Operator shall provide advance written notice to the Department and to the EPA in accordance with Condition 3(c)(2)(iii) of this permit. *[Reference: 7 **DE Admin. Code** 1130 Section 6.8.1 dated 12/11/00]*

c. The Owner and/or Operator shall keep records of any changes made under Condition 4 of this permit in accordance with Condition 3(b)(2)(iv) of this permit. *[Reference: 7 **DE Admin. Code** 1130 Section 6.8.1 dated 12/11/00]*

V. Compliance Schedule

This permit does not contain a compliance schedule. *[Reference: 7 **DE Admin. Code** 1130 Section 6.3.3 dated 12/11/00]*

VI. Permit Shield

Compliance with the terms and conditions of this permit shall be deemed compliance with the applicable requirements as provided in Condition 6 -Table 1 as of the effective date of this permit. It has been corrected to include the new regulatory citation of 7 DE. Admin Code. *[Reference: 7 **DE Admin. Code** 1130 Section 6.6.3 dated 12/11/2000*

Condition 6 – Table 1 – Part 1

Emission Unit	Applicable Requirement
1. Emission Unit 29	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108 v. 7 **DE Admin. Code** 1112 Section 4.1 vi. 7 **DE Admin. Code** 1114 Section 2.1 vii. 7 **DE Admin. Code** 1119 viii. 7 **DE Admin. Code** 1120 Section 1.2, 1.3, 1.4 and 11 ix. 7 **DE Admin. Code** 1124 Sections 1-10, 28 and 29 x. 40 CFR Part 60 Subpart J xi. 40 CFR Part 60 Appendix B xii. 40 CFR Part 6 Appendix F
2. Emission Unit 32	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108 v. 7 **DE Admin. Code** 1112

Emission Unit	Applicable Requirement
	vi. 7 **DE Admin. Code** 1114 Section 2.1 vii. 7 **DE Admin. Code** 1119 viii. 7 **DE Admin. Code** 1121 Sections 14 and 15 ix. 7 **DE Admin. Code** 1124 Section 1-10, 28, 29 and 50 x. 40 CFR Part 61 Subpart J xi. 40 CFR Part 61 Subpart V xii. 40 CFR Part 61 Subpart Y xiii. 40 CFR Part 61 Subpart BB xiv. 40 CFR Part 63 Subpart F xv. 40 CFR Part 63 Subpart G xvi. 40 CFR Part 63 Subpart H xvii. 40 CFR Part 63 Subpart CC
3. Emission Unit 33	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108 v. 7 **DE Admin. Code** 1112 vi. 7 **DE Admin. Code** 1114 Section 2.1 vii. 7 **DE Admin. Code** 1119 viii. 7 **DE Admin. Code** 1124 Section 1-10, 28 and 29 ix. 40 CFR Part 60 Subpart GGG
4. Emission Unit 34	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108 v. 7 **DE Admin. Code** 1112 vi. 7 **DE Admin. Code** 1114 Section 2.1 vii. 7 **DE Admin. Code** 1119 viii. 7 **DE Admin. Code** 1120 ix. 7 **DE Admin. Code** 24 Section 1-10, 28, 29 and 30 x. 40 CFR Part 60 Subpart Kb xi. 40 CFR Part 60 Appendix B xii 40 CFR Part 60 Appendix F xiii. 40 CFR Part 63 Subpart CC
5. Emission Unit 36	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108 v. 7 **DE Admin. Code** 1112 vi. 7 **DE Admin. Code** 1114 Section 2.1 vii. 7 **DE Admin. Code** 1119 viii. 7 **DE Admin. Code** 1124 Sections 1-10, 28 and 29
6. Emission Unit 40	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1108

Emission Unit	Applicable Requirement
	v. 7 **DE Admin. Code** 1114 Section 2.1 vi. 7 **DE Admin. Code** 1119 vii. 7 **DE Admin. Code** 1120 Sections 13 and 27 viii. 7 **DE Admin. Code** 1124 Sections 1-10, 30 and 31 ix. 40 CFR Part 60 Subpart Ka x. 40 CFR Part 60 Subpart Kb xi. 40 CFR Part 63 Subpart CC
7. Emission Unit 43	i. 7 **DE Admin. Code** 1102 ii. 7 **DE Admin. Code** 1103 iii. 7 **DE Admin. Code** 1104 Section 2.1 iv. 7 **DE Admin. Code** 1119 v. 7 **DE Admin. Code** 1120 Section 1.2, 1.3, 1.4 and 22 vi. 7 **DE Admin. Code** 1124 Sections 1-10, 28 and 29 vii. 40 CFR Part 60 Subpart GGG viii. 40 CFR Part 60 Subpart QQQ ix. 40 CFR Part 63 Subpart CC
8. Facility-wide	i. 7 **DE Admin. Code** 1103 ii. 7 **DE Admin. Code** 1104 Section 2.1 iii. 7 **DE Admin. Code** 1117 Section 2.2 and 7 iv. 7 **DE Admin. Code** 1119 Section 2.1 v. 7 **DE Admin. Code** 1124 Section 1-10, 9, 28, 29, 40 and 50 vi. 40 CFR Part 60 Subpart VV vii. 40 CFR Part 63 Subpart CC

Condition 6 – Table 2 – Part 2

Emission Unit	Applicable Requirement
1. Emission Unit 10	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1108, section 2.1 v. **7 DE Admin. Code** 1112, Section 4.1 vi. **7 DE Admin. Code** 1114, Section 2.1 vii. **7 DE Admin. Code** 1120 viii.**7 DE Admin. Code** 1124, Sections 1-10, 26, 28, 29 and 36 ix. 40 CFR Part 60, Subpart J x. 40 CFR Part 60, Subpart QQQ xi. 40 CFR Part 62, Subpart FF xii. 40 CFR Part 63, Subpart CC

Emission Unit	Applicable Requirement
2. Emission Unit 15	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1108, Section 2.1 v. **7 DE Admin. Code** 1112 vi. **7 DE Admin. Code** 1114, Section 2.1 vii. **7 DE Admin. Code** 1117, Section 2.2 viii. **7 DE Admin. Code** 1120 ix. **7 DE Admin. Code** 1124, Section 1-10, 28, 29 and 43 x. 40 CFR Part 60, Subpart A xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 63, Subpart Y xiii. 40 CFR Part 63, Subpart CC
3. Emission Unit 21	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1108, Section 2.1 v. **7 DE Admin. Code** 1109, Section 1.1 vi. **7 DE Admin. Code** 1112 vii.**7 DE Admin. Code** 1114, Section 2.1 viii.**7 DE Admin. Code** 1117, Section 2.3 ix. **7 DE Admin. Code** 1120 x. **7 DE Admin. Code** 1124, Section 1-10 and 29 xi. **7 DE Admin. Code** 1125 xii. **7 DE Admin. Code** 1139 xiii. 40 CFR Part 60, Subpart J xiv. 40 CFR Part 60, Subpart VV xv. 40 CFR Part 60, Appendix B xvi. 40 CFR Part 60, Appendix F xvii. 40 CFR Part 63, Subpart CC
4. Emission Unit 22	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1105 v. **7 DE Admin. Code** 1108, Section 2.1 vi. **7 DE Admin. Code** 1109, Section 1.1 vii. **7 DE Admin. Code** 1111, Section 2.1 viii.**7 DE Admin. Code** 1112, Section 3 ix. **7 DE Admin. Code** 1114, Section 2.1 x. **7 DE Admin. Code** 1117, Section 2.3 xi. **7 DE Admin. Code** 1124, Section 1-10 and 29 xii. **7 DE Admin. Code** 1139 xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 60, Appendix B xv. 40 CFR Part 60, Appendix F xvi. 40 CFR Part 63, Subpart CC
5. Emission Unit 23	i. **7 DE Admin. Code** 1102

Emission Unit	Applicable Requirement
	ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1105 v. **7 DE Admin. Code** 1108, Section 2.1 vi. **7 DE Admin. Code** 1109, Section 1.1 vii. **7 DE Admin. Code** 1111, Section 2.1 viii. **7 DE Admin. Code** 1114, Section 2.1 ix. **7 DE Admin. Code** 1117, Section 2.3 x. **7 DE Admin. Code** 1120 xi. **7 DE Admin. Code** 1124, Sections 1-10 and 29 xii. **7 DE Admin. Code** 1139 xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 63, Subpart CC xv. 40 CFR Part 63, Subpart UUU
6. Emission Unit 24	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1120 iv. **7 DE Admin. Code** 1124, Section 1-10 and 29 v. 40 CFR Part 60, Subpart J vi. 40 CFR Part 60, Subpart VV vii. 40 CFR Part 60, Appendix B viii. 40 CFR Part 60, Appendix F ix. 40 CFR Part 63, Subpart CC
7. Emission Unit 25	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1105, Section 2.1 v. **7 DE Admin. Code** 1108, Section 2.1 vi. **7 DE Admin. Code** 1112, Section 3 vii. **7 DE Admin. Code** 1114, Section 2.1 viii. **7 DE Admin. Code** 1117, Section 2.3 ix. **7 DE Admin. Code** 1120 x. **7 DE Admin. Code** 1124, Sections 1-10 and 29 xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 60, Subpart VV xiii. 40 CFR Part 60, Appendix B xiv. 40 CFR Part 60, Appendix F xv. 40 CFR Part 63, Subpart CC
8. Emission Unit 28	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1105 v. **7 DE Admin. Code** 1108, Section 2.1 vi. **7 DE Admin. Code** 1109, Section 3 vii. **7 DE Admin. Code** 1112

Emission Unit	Applicable Requirement
	viii. **7 DE Admin. Code** 1114, Section 2.1 ix. **7 DE Admin. Code** 1117 x. **7 DE Admin. Code** 1120 xi. **7 DE Admin. Code** 1124, Sections 1-10 and 29 xii. 40 CFR Part 60, Subpart J xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 60, Appendix B xv. 40 CFR Part 60, Appendix F xvi. 40 CFR Part 63, Subpart CC xvii. 40 CFR Part 63, Subpart UUU
9. Emission Unit 37	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1108, Section 2.1 v. **7 DE Admin. Code** 1112, Section 3 vi. **7 DE Admin. Code** 1114, Section 2.1 vii. **7 DE Admin. Code** 1117, Section 2.3 viii. **7 DE Admin. Code** 1124, Sections 1-10, 29 and 50 ix. **7 DE Admin. Code** 1139 x. 40 CFR Part 60, Subpart VV xi. 40 CFR Part 60, Appendix B xii. 40 CFR Part 60, Appendix F xiii. 40 CFR Part 60, Subpart CC
10. Emission Unit 42	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1103 iii. **7 DE Admin. Code** 1104, Section 2.1 iv. **7 DE Admin. Code** 1108, Section 2.1 v. **7 DE Admin. Code** 1112, Section 3 vi. **7 DE Admin. Code** 1114, Section 2.1 vii. **7 DE Admin. Code** 1117, Section 2.3 viii. **7 DE Admin. Code** 1120 ix. **7 DE Admin. Code** 1124, Section 1-10 and 29 x. **7 DE Admin. Code** 1139 xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 60, Subpart VV xiii. 40 CFR Part 60, Appendix B xiv. 40 CFR Part 60, Appendix F xv. 40 CFR Part 63, Subpart CC xvi. 40 CFR Part 63, Subpart UUU
11. Emission Unit 45	i. **7 DE Admin. Code** 1102 ii. **7 DE Admin. Code** 1104 iii. **7 DE Admin. Code** 1114, Section 2.1 iv. **7 DE Admin. Code** 1117, Section 2.1 and 2.2 v. **7 DE Admin. Code** 1124, Section 1-10 and

Emission Unit	Applicable Requirement
	29 vi. 40 CFR Part 60, Subpart A vii. 40 CFR Part 60, Subpart VV
12. Emission Units 24, 26, 27 and Facility-wide	i. **7 DE Admin. Code** 1103 ii. **7 DE Admin. Code** 1114, Section 2.1 iii. **7 DE Admin. Code** 1117, Section 2.2 and 7 iv. **7 DE Admin. Code** 1119, Section 2.1 v. **7 DE Admin. Code** 1124, Section 1-10, 9, 28, 29, 40 and 50 vi. 40 CFR Part 60, Subpart VV vii. 40 CFR Part 63, Subpart CC

Condition 6 – Table 3 – Part 3

Emission Unit	Applicable Requirement
1. Emission Unit 80 Boiler Nos. 1, 2 and 3	i. 7 **DE Admin. Code** 1104 Section 2.1 ii. 7 **DE Admin. Code** 1108 Section 2.1 iii. 7 **DE Admin. Code** 1112 Section 3.2 iv. 7 **DE Admin. Code** 1114 Section 2.1 v. 7 **DE Admin. Code** 1139
2. Emission Unit 80 Boiler No. 4	i. 7 **DE Admin. Code** 1104 Section 2.1 ii. 7 **DE Admin. Code** 1108 Section 2.1 ii. 7 **DE Admin. Code** 1112 Section 3.2 iii. 7 **DE Admin. Code** 1114 Section 2.1 iv. 7 **DE Admin. Code** 1136 and 40 CFR Part 72 v. 7 **DE Admin. Code** 1139
3. Emission Unit 82	i. 7 **DE Admin. Code** 1114 Section 2.1 ii. 7 **DE Admin. Code** 1124 Section 29 and 40 CFR Part 60 subpart VV iii. 40 CFR Part 60 Subpart A
4. Emission Unit 50	i. 7 **DE Admin. Code** 1105 Section 2
5. Emission Unit 84	i. 7 **DE Admin. Code** 1104 Section 2.1 ii. 7 **DE Admin. Code** 1108 Section 2.1 iii. 7 **DE Admin. Code** 1112 Section 3.5 iv. 7 **DE Admin. Code** 1114 Section 2.1 v. 7 **DE Admin. Code** 1120 Section 26 and 40 CFR Part 60 Subpart D6 vi. 7 **DE Admin. Code** 1120 Section 11 and 40 CFR Part 60 Subpart J

Emission Unit	Applicable Requirement
	vii. 7 **DE Admin. Code** 1120 Section 10 and 40 CFR Part 60 Subpart GG viii. 7 **DE Admin. Code** 1125 Section 2 ix. 7 **DE Admin. Code** 1139 Section 2
6. Facility-wide	i. 7 **DE Admin. Code** 1114 Section 2.1 ii. 7 **DE Admin. Code** 1117 Section 4 iii. 7 **DE Admin. Code** 1119 Section 2.1

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Ravi Rangan, P.E.